STAPPA
STATE AND TERRITORIAL AIR POLLUTION PROGRAM ADMINISTRATORS

ALAPCO
ASSOCIATION OF LOCAL AIR POLLUTION CONTROL OFFICIALS

Controlling Nitrogen Oxides Under the Clean Air Act:

A Menu of Options

July 1994

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Acknowledgements

On behalf of the State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, we are pleased to provide *Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options.*

This document is intended to serve as guidance to ozone nonattainment areas where reductions in emissions of nitrogen oxides will contribute to attainment of the health-based ozone standard. As such, its purpose is to assist affected areas in identifying options for controlling NO_X emissions from stationary, area and mobile sources and in evaluating those options for possible inclusion in an area's plan for demonstrating achievement of post-1996 reasonable further progress milestones and attainment.

As the November 15, 1994 deadline for submitting ozone attainment demonstrations for all Serious, Severe and Extreme and some Moderate ozone nonattainment areas draws near, we are hopeful that this document will be a valuable tool. While we recognize that not all control options included in this document are appropriate for all areas, we encourage state and local air quality agencies in need of NO_X reductions to consider the options we have identified and, where appropriate, implement the recommendations offered by STAPPA and ALAPCO. We do, however, stress the need for all agencies to conduct their own thorough analyses of all control options to ensure that the specific conditions of an area are adequately evaluated.

STAPPA and ALAPCO gratefully acknowledge the assistance of the U.S. Environmental Protection Agency's Office of Air Quality Planning and Standards (OAQPS) and Office of Mobile Sources (OMS) in the preparation of this document. In particular, we extend our appreciation to Tom Helms, William Johnson and Bill Neuffer of OAQPS and Gary Dolce of OMS, who were extremely helpful to our efforts. We note that EPA's assistance in this STAPPA/ALAPCO project should not be construed as an endorsement of the analyses and recommendations included herein.

STAPPA and ALAPCO also wish to express gratitude to Esi International, for its extensive involvement in developing this document. Additionally, we extend appreciation to Michael Walsh, for his contributions to this effort.

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Pollutants Committees, respectively, and JOHN ELSTON (New Jersey) and RICHARD BALDWIN (Ventura, CA), Chairmen of the STAPPA and ALAPCO Mobile Sources and Fuels Committees, respectively, under whose guidance this document was prepared, as well as the members of the STAPPA/ALAPCO NO_X CONTROL OPTIONS TECHNICAL REVIEW COMMITTEE, for their diligent and valuable contributions.

Finally, we greatly appreciate the STAPPA/ ALAPCO staff who oversaw this project and edited the document—S. WILLIAM BECKER, Executive Director; NANCY KRUGER, Staff Associate; VICTORIA SCHOBEL, Staff Associate; TODD FRIEDMAN, Office Manager; and CHRISTINA TUCKER, Administrative Assistant.

Once again, we believe that *Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options* will serve as a useful and important resource and are appreciative of those who contributed to its development.

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About STAPPA and ALAPCO

The State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials are the national associations of state and local air quality control officials in the states and territories and over 165 major metropolitan areas throughout the country. The members of STAPPA and ALAPCO have primary responsibility for implementing our nation's air pollution control laws and regulations. Both associations serve to encourage the exchange of information and experience among air pollution control officials; enhance communication and cooperation among federal, state and local regulatory agencies; and facilitate air pollution control activities that will result in clean, healthful air across the country. STAPPA and ALAPCO have joint headquarters in Washington, DC.

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Introduction

Statutory Background

The Clean Air Act Amendments of 1990 represent an unprecedented commitment to protecting public health and the environment. Title I of the Act classifies areas that exceed health-based National Ambient Air Quality Standards based upon the severity of their ozone nonattainment problems. Specifically, each ozone nonattainment area is designated as Marginal, Moderate, Serious, Severe or Extreme. Based upon an area's classification, the Act prescribes increasingly stringent measures that must be implemented and sets new deadlines for achieving the standards. The Act also establishes specific interim emissions reduction requirements to ensure that continuous progress toward attainment is made.

By November 15, 1993, all areas of the country classified as Moderate or above for ozone nonattainment were to submit to the U.S. Environmental Protection Agency (EPA) a plan demonstrating how emissions of volatile organic compounds (VOCs) — which contribute to the formation of ozone — will be reduced by 15 percent from 1990 levels by 1996. Under the Act, areas that failed to submit or implement an approvable plan within the applicable timeframe will be subject to nondiscretionary economic sanctions in the form of withheld federal highway funds or requirements for new industrial sources to offset emissions by a two-to-one ratio.

In addition, all ozone nonattainment areas classified as Serious or above must, by November 15, 1994, submit a plan that demonstrates continued progress beyond 1996, such that a minimum VOC reduction of at least 3 percent of baseline emissions (i.e., 1990 levels) is achieved each year. In lieu of a VOC-only reduction plan, a state may choose to demonstrate reductions in both VOCs and nitrogen oxides (NO_X), provided such a strategy reduces ozone concentrations by at least as much as would result under a VOC-only strategy, as per Section 182(c)(2)(C) of the Act.

Scope and Implications of the Ozone Nonattainment Problem

Of the six criteria pollutants for which health-based National Ambient Air Quality Standards have been established — ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide and lead — ozone poses the most pervasive problem.

Ozone is not emitted directly into the air by any source, but, rather, results from chemical reactions that occur when precursor emissions of VOCs and NO_X are exposed to sunlight. As a result of the role played by sunlight and high temperatures in the formation of ozone, peak ozone levels typically occur during the summer.

Currently, over 90 areas across the country are classified nonattainment for ambient ozone. The failure of these areas to meet the health-based ozone standard poses potential health risks to the more than 100 million individuals who live and work in these areas. Although no one residing in an ozone nonattainment area appears to be totally immune to the adverse health effects related to excessive ozone concentrations, pre-adolescent children, adults over 65 years old and individuals who suffer from respiratory disease are most at risk.

EPA has concluded, however, that even healthy individuals who exercise during hours when ozone levels are at or slightly above the current 0.12-parts-per-million (ppm) standard can experience a decrease in lung function and may suffer from a variety of ailments, including chest pain, labored breathing, wheezing, coughing, sore throat, nausea, pulmonary and nasal congestion and increased respiratory rate, which do not always subside when the ozone episode passes. Moreover, studies have revealed not only that permanent lung damage may occur from repeated and prolonged exposure to ozone, but also that susceptibility to severe respiratory infection may result in normally healthy individuals even when levels of ozone are as much as one-third below the current health-based standard (i.e., 0.08 ppm).

In addition to health consequences, elevated ozone levels are also responsible for ecosystem and forest damage and for the loss of several billion dollars of agricultural crop yield each year, as well as noticeable foliar damage in many species of trees.

Principles of NO_X Formation

Almost all NO_X emitted in the U.S. is produced in combustion processes, such as those using boilers, heaters, incinerators and engines. This NO_X is generated in one of three forms, each of which contributes to total NO_X emissions from combustion sources in varying proportions.

Fuel NO_X is produced through the oxidation of nitrogen-containing compounds in the fuel source. For fuels with a relatively high nitrogen content, such as coals and residual oils, emissions of fuel NO_X may be significant. Combustion conditions determine the fraction of the nitrogen in fuels that is emitted as NO_X. Further, as a fuel's nitrogen content increases, the amount of this nitrogen converted to NO_X decreases, with the balance converted to nitrogen gas.

Thermal NO_X is produced at temperatures above about 2000°F by the reaction of molecular nitrogen and oxygen in the combustion air. The amount of thermal NO_X formed increases by the square root of the oxygen concentration, but increases exponentially with increasing temperature. Each 130°F increase in temperature results in an approximate ten-fold increase in the rate of NO_X formation.

Prompt NO_X is formed in relatively small amounts and, therefore, contributes significantly to NO_X emissions only when overall emissions are low. The reaction of molecular nitrogen in the combustion air with hydrocarbon radicals in the flame front results in the formation of nitrogen-containing intermediates, which undergo further oxidation reactions to produce NO_X.

Overview of NO_X Control Strategies

There are two fundamental strategies for controlling NO_X emissions from combustion sources: 1) preventing the NO_X from forming and 2) destroying the NO_X after it has been formed. The NO_X formation processes described above are receptive to a variety of combustion modifications to limit the generation of NO_X; these are identified below, along with common post-combustion, or NO_X-destruction, strategies.

Low Excess Air. Reducing the amount of combustion air in excess of that needed to complete combustion of the fuel results in lower oxygen concentration in the combustion zone. This limits the formation of thermal NO_X. In boilers and process heaters, this technique is known as low excess air. In reciprocating engines, a related technique involves adjustment of the air-to-fuel ratio.

Staged Combustion: Burners Out-of-Service and Overfire Air. In staged combustion, only a portion of the combustion air is introduced with the fuel, so that primary combustion occurs under fuel-rich (oxygen-depleted) conditions, with the remainder of the air introduced separately to complete combustion. In the primary combustion zone, a lack of oxygen limits the formation of both fuel and thermal NO_X. Further, having combustion occur in a larger volume lowers peak flame temperatures, again retarding thermal NO_X formation.

Staged combustion may be implemented in boilers in several ways. All of the fuel may be introduced through half of the burners in a boiler, while maintaining air flow through all of the burners. This creates fuel-rich conditions at the active burners, but provides enough air to complete combustion. More formally, all of the burners may be operated at reduced air flow, with the balance of the combustion air introduced through overfire air ports added above the top row of burners.

Staged Combustion: Low NO_X Burners. Rather than staging combustion throughout a furnace, staged combustion burners can be used. Often, these will stage the combustion air to produce a fuel-rich zone, followed by a fuel-lean zone(s). Some burners stage fuel input, to create a cooler, fuel-lean primary combustion zone, in which thermal NO_X formation is reduced.

Fuel Gas Recirculation. Recirculating a portion of the cooled flue gas to the burners results in lower peak flame temperatures, as the flue gas serves as an inert diluent. Thus, flue gas recirculation is effective for limiting thermal NO_X formation.

Water/Steam Injection. An alternative method of lowering peak flame temperatures in smaller boilers and turbines is the injection of water or steam into the combustion zone. As is the case with flue gas recirculation, injection of water or steam reduces the formation of thermal NO_X, but has little influence over the amount of fuel NO_X generated.

Reburn. Rather than preventing the formation of NO_X, reburn functions by destroying NO_X formed in primary combustion. In reburn, some fraction of the boiler fuel will be diverted to a fuel-rich reburn zone above the burners. In this reburn zone, NO_X formed in primary combustion is reduced to N_2 by incompletely oxidized fuel molecules. Combustion is completed in a final overfire air zone.

Selective Catalytic Reduction. Selective catalytic reduction (SCR), like reburn, destroys NO_X that has been formed during primary combustion. However, rather than using additional fuel as a reducing agent, typical SCR systems use ammonia injected downstream from the combustion source. The reaction of ammonia and NO_X is relatively slow and is accelerated by a catalyst. Catalysts are available for a variety of temperature ranges: platinum-based catalysts are useful at up to about 600°F, vanadia-titania catalysts at 550°F-800°F and zeolite catalysts above about 750°F.

Selective Noncatalytic Reduction. Selective noncatalytic reduction (SNCR) also uses a reducing agent, typically either ammonia (in the Exxon Thermal $DeNO_X$ process) or urea (in the Nalco Fuel Tech NO_XOUT process), to destroy NO_X. Because SNCR does not rely on a catalyst to accelerate the reducing agent-NO_X reaction(s), it requires higher temperatures, normally above about 1600°F, to function.

Combinations. In many cases, the most cost-effective control strategy will be to implement two or more of the above strategies in combination. However, using more than one control technique to address the same NO_X formation process (e.g., both water injection and flue gas recirculation limit thermal NO_X formation) will not produce additive reductions in NO_X emissions.

Purpose of this Document

In September 1993, STAPPA and ALAPCO released *Meeting the 15-Percent Rate-of-Progress Requirement Under the Clean Air Act: A Menu of Options* to assist state and local air pollution control agencies in Moderate and above ozone nonattainment areas in developing VOC control strategies to meet their 15-percent rate-of-progress requirements, as well as their 1994 attainment demonstrations.

Similarly, STAPPA and ALAPCO intend *Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options* to assist state and local air pollution control agencies in identifying and evaluating NO_X control options that will help them meet statutory deadlines and attain and maintain the ozone standard.

Section II of this document addresses stationary and area sources. For each NO_X source category identified, this document includes a source description, emissions estimates, available control strategies and costs, a notation of selected federal and state guidance documents and control efforts and a STAPPA/ALAPCO recommendation for a level of control. Much of the data included in this document is presented in the form of tables to allow for easy reference.

As indicated in the References section at the end of each chapter, this document is based on the most recent data available from the private sector, as well as from local, state and federal authorities, including the most recent drafts of EPA's Alternative Control Techniques (ACT) documents.

Section III of this document, which addresses mobile sources, is based on the mobile sources section of STAPPA/ALAPCO's *Meeting the 15-Percent Rate-of-Progress Requirement Under the Clean Air Act: A Menu of Options*. This section has been updated to focus on NO_X emissions reduction strategies and to reflect recent developments. As in Section II, this section also includes a STAPPA/ALAPCO recommendation for each mobile source control strategy.

STAPPA and ALAPCO have prepared this document to serve a national audience. It is intended as a guide to assist state and local air quality agencies in determining which programs they should consider as they develop strategies to comply with statutory requirements for clean air. The information presented in this document is in no way intended to substitute for a thorough analysis by state and local agencies using appropriate EPA guidance and other available information.

As a result of the variability of site-specific conditions, not all control strategies addressed in this document are available within the cost ranges noted, or even applicable at all, for *all* facilities within a source category. Indeed, for many of the source categories discussed, the control of NO_X emissions has received attention only recently. This document's emphasis, however, is on commercially-demonstrated control strategies and on documented costs. In addition, it is important to note that while the STAPPA/ALAPCO recommendations included in this document take into consideration what many states and localities have included as part of their Reasonably Available Control Technology regulations, they also incorporate technically feasible "post-RACT" requirements, which could result in significant additional NO_X reductions, particularly in areas in need of such reductions to attain and maintain the ozone standard. Further, the stationary and area source recommendations offered by STAPPA and ALAPCO are intended to apply to the retrofitting of NO_X controls on existing sources; other control options may be more appropriate for new sources.

Costs identified in this document are in 1993 dollars, except as noted. Capital costs are inclusive; they are meant to encompass all of the cost elements normally encountered by sources. Annual costs cover total costs for the first year of operation, including capital recovery, and are not levelized. In the case of utilities, annual costs are presented as busbar costs, reflecting incremental costs per kilowatt of electricity generated.

Numbers related to cost effectiveness reflect the cost of reducing NO_X emissions by one ton. While cost effectiveness figures allow a comparison of control costs, it must be noted that the "last" ton of NO_X controlled is always the most expensive, so that the cost effectiveness of low-efficiency (e.g., 20 percent) controls is usually better than for high-efficiency (e.g., 80 percent) controls.

Finally, NO_X emissions from the largest two or three NO_X source categories represent a majority of total NO_X emissions; thus, significant reductions in a state's NO_X emissions are usually not possible without addressing these sources.

SECTION I

Summary of STAPPA/ALAPCO Recommendations

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Summary of STAPPA/ALAPCO Recommendations

STAPPA/ALAPCO
Recommendations for Stationary and Area Sources

SOURCE CATEGORY	STAPPA/ALAPCO RECOMMENDATION
Utility Boilers	Require T-fired and wall-fired coal units to meet levels of 0.15 lb/MMBtu or below, and oil and gas units to meet levels of 0.05 lb/MMBtu (one-hour averaging period). Adopt emission rates based on energy output (e.g., lb/megawatt-hr produced), rather than heat input (e.g., lb/MMBtu). Consider, among other options, emissions averaging among units to lower control costs and provide added flexibility.
Industrial and Commercial Boilers	Set limits for boilers larger than 100 MMBtu/hr at levels of 0.15 lb/MMBtu or below for coal and 0.05 lb/MMBtu for oil and gas. Mid-sized boilers between 50-100 MMBtu/hr can achieve limits of 0.10 lb/MMBtu for gas, 0.12 lb/MMBtu for distillate oil and 0.30 lb/MMBtu for residual oil. Consider setting limits for mid-sized boilers burning coal at 0.38 lb/MMBtu and requiring smaller boilers less than 50 MMBtu/hr to make annual "tune-ups" to minimize excess air.
Process Heaters	Consider requiring limits of 0.036 lb/MMBtu for gas and 0.05 lb/MMBtu for other liquid fuels. Set limits, at a minimum, similar to those for mid-sized industrial boilers — 0.10, 0.12 and 0.30 lb/MMBtu for gas, distillate oil and residual oil-fired units, respectively.
Gas Turbines	Regulate turbines burning natural gas at levels of 25-42 ppm and as low as 9-15 ppm. Regulate turbines burning distillate oil at 65 ppm or below, and as low as 25-42 ppm.
Reciprocating Internal Combustion Engines	Set limits for rich-burn gas-fired engines between 0.4-0.8 g/bhp-hr, for lean-burn engines as low as 0.5-0.6 g/bhp-hr and for diesel engines at 0.5-1.1 g/bhp-hr.
Kraft Pulp Mills	Regulate industrial boilers (see recommendation above for Industrial and Commercial Boilers), recovery boilers (consider SNCR) and lime kilns (see recommendation below for Cement Kilns).
Cement Kilns	Require combustion controls and post-combustion controls (SNCR) to achieve reductions of up to 70 percent on certain processes.

STAPPA/ALAPCO Recommendations for Stationary and Area Sources—*continued*

SOURCE CATEGORY	STAPPA/ALAPCO RECOMMENDATION
Iron and Steel Mills	Require reductions from reheat furnaces using low NO_X burners and FGR (to achieve reductions of 50 percent or more), from annealing furnaces using SCR and low NO_X burners (to achieve reductions of 95 percent or more) and from galvanizing furnaces using low NO_X burners and FGR (to achieve reductions of 75 percent or more).
Glass Furnaces	Require combustion modifications, process changes and post-combustion controls (SNCR). RACT limits of 5.3-5.5 lbs NO_X/ton of glass removed have been adopted, as well as limits as low as 4.0 lb NO_X/ton of glass removed. Require sources to coordinate installation of controls with routine furnace rebuilds to lower costs.
Nitric and Adipic Acid Plants	Consider a standard of 2.0 lbs NO_X/ton of nitric acid produced, representing approximately 95-percent control. Even lower standards are achievable using SCR. The nation's four adipic acid plants are already regulated at over 80-percent efficiency.
Municipal Waste Combustors	Set limits of 180 ppmv based on a 24-hr average for large, existing MWCs emitting more than 250 tons/day, pursuant to EPA's upcoming regulations. Consider more stringent limits (e.g., 30-50 ppmv) or shorter averaging periods (e.g., 8-hr average).
Medical Waste Incinerators	Require controls similar to those for municipal waste combustors.
Ammonia Plants	Set controls based on those for process heaters and industrial boilers.
Organic Chemical Plants	Require controls on industrial boilers and process heaters for these sources.
Petroleum Refineries	Regulate refinery boilers and process heaters in a comparable manner to other industries. Regulate fluid catalytic cracking units by controlling CO boilers (e.g., SNCR). Require SNCR or low NO_X burners on tail gas incinerators to achieve limits of 50 ppm or lower.
Residential Space and Water Heaters	Set limit on new sources of 0.09 lb/MMBtu of heat output and consider incentives to replace older space and water heaters.
Open Burning	Restrict open burning on days when ozone exceedances are expected or reduce the amount of refuse burned by recycling municipal waste or mulching agricultural and landscaping waste.

STAPPA/ALAPCO *Recommendations for Mobile Sources*

SOURCE CATEGORY	STAPPA/ALAPCO RECOMMENDATION
Motor Vehicle Inspection and Maintenance	Consider implementation of IM240 in areas not required to adopt such a program, in that IM240 tests for NO_x and requires repairs accordingly. Also consider augmenting the program by expanding geographic coverage, increasing model year and vehicle class coverage and pre-1981 stringency rate, conducting inspections annually and/or setting tighter cutpoints.
Reformulated Gasoline and Diesel Fuel	Consider opting into the federal program or utilizing Section 211(c)(4) authority to adopt a state program, including the California RFG program or one focused on fuel properties (e.g., reducing sulfur content of fuel). Consider adopting reformulated diesel fuel requirements, including the California reformulated diesel program, to achieve additional reductions from diesel engines.
California Low-Emission Vehicles	Consider adopting the California LEV program.
Clean-Fuel Fleets	Consider adopting a CFFV program, if one is not already required. Where a CFFV program is required, increase its reduction potential by purchasing more CFFVs than called for in any year, purchasing vehicles that meet stricter emission standards than those required, or purchasing vehicles in advance, before requirements take effect. Areas may also encourage non-covered fleets to participate and/or require the purchase of ILEVs where fleet requirements from the Energy Policy Act are applicable.
Nonroad Vehicles and Engines	In addition to EPA's regulations on 50-hp and above nonroad diesel engines, explore scrappage programs, among others, for near-term reductions and to increase turnover of these sources, particularly for construction equipment.
Transportation Control Measures	Evaluate the potential effectiveness of TCMs based upon the particular needs and circumstances of a given area, emphasizing pricing strategies, such as parking management, traffic flow improvements and road pricing.
Employee Commute Options	In areas not already required to implement an ECO program, evaluate the potential emission reductions to be achieved by implementing such a program and consider its implementation to achieve additional reductions and stabilize mobile source emissions.
Accelerated Vehicle Retirement	Consider implementing an accelerated vehicle retirement, or "scrappage," program in conjunction with an I/M program.

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SECTION II

Stationary and Area Sources

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Utility Boilers

Summary

Utility boilers burn fuel to produce steam used in the generation of electricity. Fossil-fuel-burning utility boilers account for approximately 70 percent of the U.S. electricity supply, with the predominant fuel (80 percent) being coal.

Uncontrolled NO_X emissions from coal-fired utility boilers generally range from 0.5-1.5 lb/MMBtu on a heat input basis, or 4.7-14 lb/MWh on an electrical output basis, although some units have emissions as high as 2.5 lb/MMBtu. For oil- and gas-fired boilers, uncontrolled emissions are approximately 0.3-0.5 lb/MMBtu, or 2.8-4.7 lb/MWh. For the entire utility boiler population, which has an aggregate annual electrical output of 1.9 trillion kWh, NO_X emissions were 7.5 million tons in 1992. There are utility boilers in almost every state.

A variety of NO_X control techniques has been installed on utility boilers. Combustion controls limit NO_X emissions by either lowering the combustion temperature (to control thermal NO_X) or limiting oxygen availability (to control fuel NO_X). Common combustion controls, such as low excess air, burners out-of-service, overfire air, low NO_X burners, flue gas recirculation and natural gas reburn, afford emissions reductions of 10-60 percent.

Post-combustion controls destroy NO_X in the flue gas using ammonia, urea or other reducing agents. Selective noncatalytic and catalytic reduction provide emissions reductions of 30-90 percent.

Other alternatives, such as fuel switching, co-firing and repowering, operate by a variety of mechanisms.

Total capital costs for retrofit NO_X controls typically are \$10-\$60/kW for combustion controls, \$10-\$20/kW for SNCR and fuel switching and \$50-\$130/kW for SCR, with costs for larger units falling at the lower ends of these ranges (see *Tables 9-11*). Removal costs for large, high-capacity factory units are \$150-\$900/ton of NO_X for combustion controls, \$600-\$1300/ton for SCR and SNCR and \$2500-\$3000/ton for fuel switching, and are higher for smaller boilers with a lower capacity factor. Specific details of each boiler will determine which technology offers least-cost control.

Description of Source

Utility boilers produce steam used to drive turbine generators for electricity production. Both utility and non-utility generators (NUG) or independent power producers (IPP) own and operate boilers that fit this definition, as do some cogenerators, which produce steam for captive use or sale and electricity for sale to the grid.

Fossil-fuel-burning utility boilers were used in the production of 1.9 trillion kWh of electricity in the U.S. in 1990. This was approximately 70 percent of total U.S. electricity production. Fuel use was divided among coal (81 percent, based on electrical output), oil (5 percent) and gas (14 percent). Only a very small number of utility boilers burn other fuels (e.g., biomass).

The electric-generating capacity of utility boilers ranges from approximately 25 to 1300 MW. Given a typical efficiency of about 33 percent, this corresponds to a heat input range of 260 to 13,400 MMBtu/hr. Boiler age is similarly variable, with some boilers over 50 years old still in service.

Depending on utility needs, boilers may be operated somewhat differently. Baseload units are run continuously at a constant, high fraction of maximum rated load. Cycling units are run at a load that varies with demand (e.g., at maximum rated load during the day and low load at night). Peaking units run only during periods of high demand, which in some cases may be limited to the few hottest days of the summer.

Boiler Designs

There are several different utility boiler designs in widespread use. The combination of boiler design and fuel determines both uncontrolled NO_x emissions and the applicability of various NO_x control strategies.

All boiler designs share a number of common elements, each of which plays a role in the selection of NO_x control technologies. Utility boilers are watertube boilers; combustion takes place in an enclosed furnace and heat is transferred from the furnace to water in tubes. In the furnace itself, heat is transferred by radiation from the combustion gases to tubes lining the walls. As gases cool and leave the furnace, the primary heat transfer mechanism becomes convection. A boiler is designed to have specific fixed temperature zones for optimum heat transfer to the watertubes; modification of these designs will affect boiler efficiency. Further, any modification of flow patterns within the furnace may affect combustion and, therefore, boiler efficiency.

For utility boilers, various types of burners are used to combust the fuel. Auxiliary to the burners are fuel supply lines, a windbox for supplying combustion air, dampers, flame scanners, ignitors and control systems. Modification or replacement of the burners may require modification of any or all of these components, and possibly waterwall modifications. Modification of the windbox may result in the need to relocate or replace boiler structural components.

Most **Coal-Fired Boilers** use pulverized coal (i.e., coal that has been crushed to a nominal diameter of 50 microns or smaller). Small particles burn rapidly, with combustion complete in one to two seconds, so that CO and hydrocarbon emissions and unburned carbon in the fly ash are minimized without the need for an unreasonably large furnace. Most pulverized-coal boilers have the same basic design (*Figure 1*) and are either wall-fired or tangentially fired arrangements.

In a **Wall-Fired Boiler**, burners are mounted in the boiler walls, producing discrete flames in the furnace. Burners may be mounted in a single boiler wall or in two opposing walls. Conventional ("circular") burners have a central nozzle for injecting a mixture of pulverized coal and primary air, with a circular register around the nozzle for supplying secondary air. (Circular burners can also fire oil or gas.) Cell burners, units of two or three vertically stacked circular burners, give higher heat release rates leading to higher peak flame temperatures and, therefore, higher uncontrolled NO_x emissions than conventional burners.

In **Tangentially Fired Boilers**, there are stacked groups of burners and air registers at the four corners of the furnace. Fuel and air are injected to create a single rotating fireball in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers have lower uncontrolled NO_x emissions than do wall-fired boilers because the stacked burner assemblies produce stratified fuel-rich and fuel-lean regions, thus simulating low NO_x burner behavior (see *Available Control Strategies* section).

Cyclone-Fired Boilers, for coals that produce low-melting ash, use crushed rather than pulverized coal. Two advantages of cyclone-fired boilers are their relatively small size and their low coal-preparation costs, given that pulverizers are not needed. Combustion occurs in horizontal cyclone furnaces attached to the boiler firebox. Because these furnaces are small, they have high heat release rates and resulting high peak flame temperatures, which melt coal ash to form slag. This slag collects in a slag tank beneath the furnace. High temperatures also result in high NO_x emissions.

Cyclones are wet-bottom boilers, so called because molten ash is collected at the bottom of the furnace. A small number of pulverized coal-fired boilers also have wet-bottom furnaces.

Stoker-Fired Boilers can use a wide variety of solid fuels and can burn coal up to about one millimeter in diameter. Stokers feed fuel onto a grate, where it burns. Primary combustion air is admitted under the grate (underfire air). A separate overfire air system supplies 15-20 percent of the air needed to complete combustion. (This overfire air results in relatively low NO_x emissions;

see *Available Control Strategies* section.) Overfeed spreader stokers, in which feeders distribute coal onto moving grates, are the most common stokers in utility use.

There are a small number of fluidized-bed boilers in the U.S. In a fluidized-bed boiler, coal is burned in a bed of inert material, commonly sand or ash, which is fluidized by air supplied from the bottom of the furnace. Turbulence in the bed promotes rapid mixing of fuel and air, leading to very uniform combustion. Good thermal contact with the bed material results in a low combustion temperature and, therefore, low uncontrolled NO_X emissions, typically on the order of 0.2 lb/MMBtu.

There are also a small number of boilers with other designs. Wet-bottom wall-fired and tangentially fired boilers may have emissions higher than their dry-bottom counterparts. Vertically fired boilers for difficult-to-burn coals have emissions comparable to wall-fired units.

Oil- and Gas-Fired Boilers are similar in design to pulverized coal boilers, but are smaller because these fuels burn more easily than coal. Most oil- and gas-burning boilers are wall-fired or tangentially fired, although a small number of cyclone boilers have been converted from coal service.

Emissions Per Unit Output

Table 1 lists estimated uncontrolled NO_X emissions for pre-NSPS boilers, based upon emissions factors contained in AP-42, EPA's *Compilation of Air Pollutant Emissions Factors*. These figures are close to the capacity-weighted emissions of existing boilers in the eight northeastern states which comprise the Northeast States for Coordinated Air Use Management (NESCAUM). Boilers constructed after August 1971 would have somewhat lower emissions.

National Emissions Estimate

The approximately 4000 fossil-fuel-burning utility boilers located at 766 electric generating facilities in the U.S. had total NO_X emissions of about 7,470,000 tons in 1992. Utility boilers contribute an estimated 72 percent of national stationary source NO_X emissions and 32 percent of total national NO_X emissions. *Table 2* lists total emissions broken down by fuel type. *Tables 3 and 4* list the number of coal-fired utility boilers and emissions, broken down by boilertype.

Geographic Distribution of Sources and Emissions

Utility boilers are located in every state in the country. In almost every state, utility boilers emit more NO_X than any other stationary source. In a number of states, including Kentucky, Nevada and North Dakota, utility boiler emissions account for over 90 percent of stationary

STAPPA/ALAPCO *Recommendation*

▶ In April 1992, STAPPA and ALAPCO recommended two phases of emission limits for controlling NO_X from utility boilers, including a second phase requiring 0.2 lb/MMBtu for coal and 0.05 lb/MMBtu for oil and gas (based upon a one-hour averaging period). Since 1992, the costs of various control strategies — including selective catalytic reduction — have fallen significantly. Technology is now available for typical tangentially fired and wall-fired coal units to be controlled in a cost-effective manner to levels of 0.15 lb/MMBtu or below. While similar post-combustion technology will provide 70-90 percent control for cyclone boilers or other wet-bottom units, these sources typically emit at higher uncontrolled rates (e.g., 1.5 lb/MMBtu or higher) and may need to be regulated separately.

State and local agencies are encouraged to adopt emission rates in terms of energy output (e.g., lb/megawatt-hour produced), rather than heat input (lb/MMBtu), in recognition of the fact that energy efficient units inherently produce less NO_X; such rates will encourage NO_X dispatching of utility boilers. Agencies are also encouraged to provide flexibility to utilities, consistent with EPA's Economic Incentive Program, in order to minimize control costs. Such flexibility could include, among other things, emissions averaging among units.

source NO_x emissions. The midwestern and mid-Atlantic states of Illinois, Indiana, Ohio and Pennsylvania account for the highest total quantity of NO_x emissions per year. See *Table 5* for a state-by-state list of electric generation facilities and emissions.

Available Control Strategies

There is a wide variety of proven strategies for controlling NO_x emissions from utility boilers. Several of these use modification of combustion conditions, such as flame stoichiometry or peak flame temperature, to prevent the formation of NO_x or to destroy NO_x formed early in the combustion process. Included among these strategies are derating, low excess air, burners out-of-service, low NO_x burners, flue gas recirculation and reburn. Selective catalytic and noncatalytic reduction, on the other hand, destroy NO_x after the completion of combustion. Finally, strategies such as fuel switching, co-firing of coal with natural gas and repowering are also available for controlling NO_x emissions.

The applicability, effectiveness and cost of each control strategy will be site specific. In particular, achievable reductions in NO_x emissions will depend upon uncontrolled emissions. Some older, "dirty" boilers with high uncontrolled emissions will be particularly amenable to large emissions reductions through simple operational modifications, while incremental reductions will be more difficult at newer, intrinsically "cleaner" boilers.

Derating (Load Reduction), or running boilers at less than their maximum rated capacities, lowers the heat release rate per unit of boiler volume, and thus decreases the production of thermal NO_x. Drafting is an option for any boiler from which power output is easily replaced, but is limited by the ability of boilers to function well at lower loads. Further, use of derating to shift emissions across a state or attainment area boundary is likely to be unacceptable as a control option. An alternative method of lowering heat release rate is enlarging the firebox. This alternative is discussed in more detail in the section on burners out-of-service.

There is no capital cost associated with derating; the primary operating cost is merely the cost of replacement power. However, boiler efficiencies may be lower at lower loads, resulting in increased fuel consumption per unit of power generated. In particular, additional combustion air may be required to ensure good fuel-air mixing and hence good combustion, in order to avoid CO, hydrocarbon and particulate emissions. This excess air results in loss of sensible heat. Excess air also may result in increased fuel NO_x formation, which can counteract the effect of the derate.

Achievable NO_x reductions are roughly proportional to the extent of derating.

Low Excess Air operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of NO_x and lowers peak flame temperatures, thus inhibiting thermal NO_x formation.

All boilers may be operated with low excess air; in fact, this often has been done not to control NO_x emissions, but to improve boiler efficiency by minimizing heat loss. Because low excess air may be attained merely through modification of boiler operation, it requires little in the way of boiler modification (for example, adjustment of air registers and dampers), and capital costs will be low. In many cases, the only capital cost will be for a parametric study of boiler operation under a variety of excess air levels. Some older boilers may require upgraded control systems to allow variable load operation with low excess air.

By using low excess air as a NO_x control technique, controlled emissions of 0.6-0.8 lb/MMBtu, corresponding to NO_x reductions of 10-20 percent, are commonly achievable for coal. With oil and gas, slightly greater emissions reductions of 10-25 percent are possible, resulting in controlled emissions of 0.2-0.4 lb/MMBtu.

Emissions reductions at low excess air are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of CO, hydrocarbons and unburned carbon increase, resulting in lower boiler efficiency. Practical limits, based on these considerations, are 15-20 percent excess air by weight for pulverized coal-fired boilers, perhaps somewhat higher than this for stokers and 3-15 percent for oil- and gas-fired boilers.

Other impediments to low excess air operation are the possibility of increased corrosion and slagging in the upper boiler as a result of the reducing atmosphere created at low oxygen levels. In stokers, because primary combustion air is also used to cool the grate, overheating of the grate, in addition to corrosion of the grate and clinker (large agglomerates of solidified molten ash) formation, may occur at low excess air.

Burners Out-of-Service (BOOS) is a method of staging combustion in the boiler by funneling all of the fuel to some of the burners, often the bottom row. This produces fuel-rich conditions at the burners that remain in service; the low oxygen availability during primary combustion reduces formation of both thermal and fuel NO_x. The balance of combustion air is admitted through the burners out-of-service.

BOOS is applicable to many wall-fired and tangentially fired boilers and typically requires little equipment modification and, thus, small capital outlays. However, the burners that remain in service must have sufficient capacity to handle the extra fuel flow to avoid a boiler derate. In the case of coal-fired units, the pulverizers for the burners in-service must also be sufficiently large to handle the added demand. For older boilers, control system upgrades may be required.

Potential NO_x emissions reductions range from 10-20 percent for coal, based on controlled emission levels of 0.6-0.8 lb/MMBtu, and 15-35 percent for oil and gas, based on controlled emission levels of 0.2-0.35 lb/MMBtu.

Limitations on the use of BOOS include a loss in boiler efficiency as a result of the need for increased excess air to ensure good fuel-air mixing and to prevent heat damage to the idle burners. Other concerns are the potential for corrosion and slagging in fuel-rich (reducing) zones in the furnace and for increased stack opacity and CO emissions.

Overfire Air allows staged combustion by supplying less than the amount of air theoretically needed for complete combustion through the burners, with the remaining air injected into the furnace through overfire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of fuel NO_x, while having combustion occur over a larger portion of the furnace lowers peak flame temperatures, thus limiting thermal NO_x formation.

As used here, overfire air for wall-fired boilers refers both to conventional overfire air, in which burners and overfire air ports use the same windbox, and to advanced overfire air, in which the overfire air ports have a dedicated windbox. In advanced overfire air systems, there is better control of the overfire air supply, as well as greater flexibility to locate the overfire air ports for maximum control effectiveness.

In the case of tangentially fired boilers, close-coupled overfire air uses the burner windbox and includes overfire air ports contiguous to the burner array. Separated overfire air, analogous to advanced overfire air, uses a separate windbox, with some spacing between the burner array and the overfire air ports.

Overfire air is applicable to stokers and most tangentially and wall-fired boilers. In order to be amenable to the use of overfire air, pulverized coal-fired boilers must have sufficient space between the top row of burners and the furnace exit to allow installation of overfire air ports; there must also be sufficient distance between these ports and the furnace exit to allow complete combustion of the fuel. Overfire air is not applicable to cyclone (or other slagging) boilers because changing heat release rates changes slagging rates and slag properties and interferes with normal cyclone operation.

Retrofit of overfire air onto boilers typically requires extension of the existing windbox or installation of a new one. The need for several overfire air ports to ensure good mixing implies a need for extensive waterwall modification and perhaps for relocation of structural supports. In many cases, an upgraded control system also may be required.

Overfire air and advanced overfire air have been retrofitted on a number of pulverized coal-fired utility boilers. Overfire air normally is an integral part of stoker design and, therefore, is installed on most, if not all, stoker boilers.

Controlled emission levels achievable through the use of overfire air are 0.5-0.8 lb/MMBtu for pulverized coal and 0.2-0.4 lb/MMBtu for oil and gas. These numbers correspond to removal efficiencies of 10-30 percent and 14-45 percent, respectively. For coal-fired stokers, removal efficiencies are 5-10 percent.

Poorly controlled overfire air may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash of coal-fired boilers. These products of incomplete combustion would be accompanied by decreased boiler efficiency. Among other concerns related to overfire air use are that reducing conditions in the lower furnace may lead to corrosion and that increased furnace exit temperatures may affect boiler performance or damage tubes in the convectively heated section of the boiler. In stokers, too little underfire air (caused by diversion of combustion air to overfire air ports) may lead to overheating of the grate, as well as corrosion of the grate and clinker formation.

Low NO_x Burners integrate staged combustion into the burner. A typical low NO_x burner creates a fuel-rich primary combustion zone. The reducing conditions in this zone promote the reduction of fuel NO_x, while limited combustion air lowers the flame temperature, minimizing the production of thermal NO_x. Combustion is completed in a lower-temperature, fuel-lean zone.

Low NO_x burner technology is applicable to most wall-fired and tangentially fired boilers. It is not applicable to stokers, which have no burners, or to cyclones, which must maintain rigidly defined combustion conditions for proper slagging. Because low NO_x burners produce longer flames, they may be inappropriate for retrofit on smaller furnaces.

Note that in tangentially fired boilers, low NO_x burners normally include close-coupled overfire air.

The relative ease of low NO_x burner retrofits varies. In some cases, "plug-in" replacement burners may be installed without modification of other boiler components. However, in other cases, low NO_x burners will not fit in existing openings, requiring modification of the waterwall and windbox, and other related structural modifications. Further requirements may include upgraded electrical and control systems, additional windbox dampers and baffles, fan modifications and, in the case of coal, coal pipe and pulverizer modifications. In some cases, additional work that is not strictly related to burner operation (e.g., asbestos removal) may be necessary. Depending upon the boiler, space constraints may make low NO_x burner retrofit more difficult and increase installation costs.

Low NO_x burners have been installed on a large number of utility boilers in the U.S., including over 40 wall-fired and tangentially fired pulverized coal boilers. On coal-burning wall-fired boilers, controlled emissions of 0.45-0.55 lb/MMBtu correspond to emissions reductions of approximately 40-50 percent. On tangentially fired boilers, controlled emissions are 0.50-0.55 lb/MMBtu, resulting in emissions reductions of 20-25 percent. For oil- and gas-burning boilers, low NO_x burners provide controlled emissions of 0.15-0.35 lb/MMBtu or emissions reductions of 30-50 percent.

Installation of low NO_x burners may be accompanied by increased emissions of CO and hydrocarbons, and in the case of coal, by increased unburned carbon. These products all signal less-than-complete combustion and, hence, reduced boiler efficiency and increased fuel costs. Unburned carbon also may change fly ash properties, affecting the downstream performance of electrostatic precipitators and, in the worst case, making the fly ash unsalable.

Low NO_x Burners and Overfire Air in combination perform well and have been installed together on boilers throughout the U.S., including 20 coal-fired boilers. The cost of the retrofit of the two together is less than that of separate retrofits.

Because low NO_x burners in tangentially fired boilers include close-coupled overfire air, this section refers to the combination of low NO_x burners with separated overfire air

Controlled emissions are 0.3-0.5 lb/MMBtu for coal-fired boilers, and 0.15-0.3 lb/MMBtu for oil- and gas-fired boilers, corresponding to emissions reductions of 50-70 percent (wall-fired coal), 30-50 percent (tangentially fired coal) and 40-50 percent (oil and gas).

Flue Gas Recirculation (FGR) involves recycling of up to about 20 percent of the cooled flue gas back to the combustion zone. FGR lowers peak flame temperature primarily by adding a large mass of cool, inert gas to the fuel-air mixture. FGR also lowers the oxygen concentration in the flame.

Because FGR reduces thermal NO_x formation and has only a small effect on fuel NO_x levels, its principal applicability is to oil- and gas-fired boilers. However, FGR is also applicable to coal-fired stoker boilers; by replacing the combustion air flowing through the grate, it allows operation at reduced boiler excess air levels without grate overheating.

Retrofitting FGR onto existing boilers requires installation of ductwork, recirculation fans, air foils for mixing recirculated flue gas and combustion air and controls for variable load operation. Simultaneous installation of overfire air ports may be necessary if the existing burners are unable to accommodate the increased mass flow at full load. This increased flow would lead to large pressure drops across the burners and could lead to burner instabilities.

FGR is commercially proven. On oil- and gas-fired boilers it affords controlled emissions of 0.2-0.3 lb/MMBtu (wall-fired) and 0.1-0.2 lb/MMBtu (tangentially fired), for emissions reductions of approximately 40-60 percent.

Lower temperatures and altered temperature profiles attributable to FGR may result in reduced boiler efficiency.

Reburn uses a second, fuel-rich combustion zone above the top row of burners to reduce NO_x formed in primary combustion. Between 15 and 30 percent of the boiler heat input is introduced into this reburn zone. In order to complete combustion of the reburn fuel, overfire air is injected in a burnout zone at the top of the furnace.

While any fuel may be used for reburn, most demonstrations have been conducted with natural gas.

Reburn technology should be applicable to many oil-, gas-, and pulverized-coal-fired boilers. It will be particularly useful for cyclone boilers, which are not amenable to the use of other combustion controls. Reburn requires substantial boiler modifications, including the installation of reburn burners and associated piping, ductwork, windbox and controls, as well as overfire air and its associated systems. Installation of the reburn burners and overfire air ports will require waterwall modifications. Use of gas as the reburn fuel may require a pipeline extension, while use of coal in a cyclone boiler may require the installation of pulverizers.

Reburn has been demonstrated in long-term tests on coal-burning tangentially fired and cyclone boilers, and also on gas-burning boilers. There are no commercial applications of reburn in the U.S.

The effectiveness of reburn will vary with the fraction of the total boiler heat input that is used as reburn fuel; this may be limited at reduced loads. Typical emissions reductions of 50-60 percent are expected, with controlled emissions of 0.4-0.5, 0.3-0.4 and 0.6-0.75 lb/MMBtu, respectively, on coal-burning wall, tangential and cyclone boilers, and perhaps half these values on boilers burning oil and gas.

Use of natural gas as the reburn fuel on coal-fired boilers has the additional benefit of lowering emissions of SO_2. This should lower net operating costs through the generation of salable allowances currently worth about \$200/ton.

Reburn has the potential to cause slagging and corrosion in the upper furnace.

Selective Catalytic Reduction (SCR) is the catalyst-mediated reduction of NO_x with ammonia or other reducing agents to produce nitrogen gas and water. On utility boilers, the catalyst normally is placed between the economizer and air heater ("hot-side" configuration; see *Figure* 2) in order to minimize costs. "Cold-side" configurations, in which the catalyst is placed downstream of the air heater, require the flue gas to be reheated to the catalyst operating temperature and, thus, are more expensive to build and operate.

SCR should be applicable to nearly all utility boilers, provided that space limitations do not preclude the installation of the catalyst and auxiliary systems. SCR has been retrofitted on several large gas-fired utility boilers in southern California, with Southern California Edison alone having announced plans to retrofit SCR on 20 boilers with a total capacity of about 8,000 MW. SCR systems are also in operation on two new 110-MW coal-fired boilers in New Jersey, with several others planned or under construction. There is extensive retrofit experience in Europe and Japan, where systems have been operating on coal- and oil-fired utility boilers for over 15 years.

Required SCR retrofit components include the catalytic reactor, associated ducting and structural work, the ammonia storage and distribution system and controls. Other components that may be necessary include an economizer bypass (if the economizer exit temperature drops below the minimum catalyst operating temperature at low boiler load), sootblowers (in coal- and heavy-oil-firing applications), a fan upgrade (to overcome the additional pressure drop across the catalyst) and an air heater upgrade. Because the catalytic reactor is large, perhaps on the order of a 40-foot cube for a 500-MW coal-fired boiler, its installation may require relocation of existing equipment. Space constraints may increase construction costs.

Two alternative catalyst arrangements have been devised to decrease retrofit costs, as well as to allow retrofits where crowding prevents installation of a conventional SCR system. In-duct SCR involves installation of the catalyst in existing ductwork between the economizer and preheater. Air heater SCR is implemented by coating the preheater baskets with catalytically active material. Both arrangements avoid much of the construction expense, but limit the amount of catalyst that may be installed. Tests in California and abroad have shown both to work.

In some cases, a design intermediate between conventional and true in-duct SCR has been installed. This design, which has been used in California, is based on an in-line reactor that is smaller than a conventional SCR reactor, but larger than the existing duct.

SCR is capable of providing the highest NO_x removal efficiency of all control technologies, and its performance is limited only by acceptable cost. On oil- and gas-fired boilers, guaranteed emissions reductions of 90 percent and greater are common, so that controlled emissions below 0.05 lb/MMBtu are possible. Design emissions reductions on coal-fired boilers have been sufficient to meet permit limits. Assuming 80-percent emissions reductions, which are readily achievable, controlled emissions would be less than 0.2 lb/MMBtu for pulverized-coal-fired and stoker boilers and less than 0.3 lb/MMBtu for cyclone boilers. In fact, the new pulverized-coal-fired Orlando Utilities Commission Stanton Unit 2 in Florida will use SCR to meet a 0.17 lb/MMBtu permit limit.

Despite early concerns, European and Japanese experiences suggest an SCR catalyst life of over five years for coal and somewhat longer for oil and gas. Catalyst poisoning, plugging and erosion have posed limited problems, even when burning dirty, high-ash coals. Given long lives, annual catalyst replacement costs are relatively low. A low replacement rate also lowers catalyst disposal costs, as does a catalyst recycling service provided by at least one manufacturer.

Two issues are associated with the use of ammonia as a reagent for reducing NO_x. First, ammonia slip, or the emission of unreacted ammonia, cannot be prevented, but may be controlled to levels below 2 ppm in properly designed SCR systems. At such low levels, fly ash properties, and hence sales, should be unaffected. Second, anhydrous ammonia, used in most SCR systems to date, is hazardous, requiring precautions to prevent catastrophic releases. As a non-hazardous alternative, aqueous ammonia is becoming common, but is more expensive and requires more storage space.

When sulfur-bearing fuels are burned, a third issue is associated with the use of ammonia. It reacts with flue gas SO_3 to form ammonium bisulfate, which collects on the air heater and other downstream surfaces. Ammonium bisulfate formation is exacerbated by the ability of SCR catalysts to oxidize SO_2 to SO_3. While ammonium bisulfate formation may be lessened by controlling ammonia slip and using catalysts that minimize SO_2 oxidation, it cannot be avoided, particularly when high-sulfur fuels are used. Provisions for periodic water washes of the air heater and other components must be made to prevent ammonium bisulfate buildup.

Selective Noncatalytic Reduction (SNCR) uses ammonia or urea injected into the upper reaches of the furnace to reduce NO_x to nitrogen and water (see *Figure* 2). The NO_x-destroying reactions are driven by the high temperatures found in the boiler. When necessary, other reagents may be injected to widen the effective temperature window for these reactions.

SNCR is applicable to most utility boilers. However, some boilers will not provide the right combination of gas temperature and residence time to support reasonable NO_x reductions, or will have tube banks blocking preferred injection port locations. There have been demonstrations of SNCR on coal-, oil- and gas-fired utility boilers ranging in output up to 850 MW, although most tests have been on boilers under 200 MW. SNCR is installed on New England Electric System's Salem Harbor Units 1-3 in Massachusetts, which have pulverized coal boilers with capacities of 84 to 156 MW, and is being installed on Montaup Electric Company's Somerset Unit 6 in Massachusetts, which has tangentially fired pulverized coal boilers.

Equipment needs for retrofitting SNCR onto utility boilers include reagent storage, distribution and control systems, with the control system often skid-mounted; installation requires minimal boiler downtime. Preparatory to installation is a study of the temperature and flow profiles in the boiler, in order to determine optimum locations for reagent injection ports. For variable load units, multiple injection levels are typically needed.

SNCR system performance depends on temperature and flow profiles in the boiler and on the level of uncontrolled NO_x. The largest reductions should be possible on boilers with the highest initial NO_x levels, as thermodynamic considerations limit reductions on cleaner units. At some gas-fired boilers with very low uncontrolled NO_x levels, no emissions reductions may be possible using SNCR. In general, achievable reductions are comparable to those attainable with low NO_x burners and are 30-60 percent on coal-fired boilers and 25-40 percent on oil- and gas-fired boilers.

Ammonia slip generated by SNCR often can be limited to about 5-10 ppm at acceptable NO_x emissions reductions, although it may be considerably higher. At the 5-10 ppm level, slip may affect fly ash properties, and sales, at coal-burning units. Further, relatively high ammonia concentrations in the boiler can lead to ammonium bisulfate formation, with deposition on the economizer, air heater and other surfaces. In at least one case, plugging of filter bags in a baghouse has occurred. If reagent injection ports are not located properly in the boiler, or if load-following controls are ineffective, the ammonia slip problem will be exacerbated. When high-chloride coals are burned, ammonia slip may cause the ancillary problem of visible ammonium chloride plumes. Reagent storage and handling must also be considered.

SNCR also generates nitrous oxide emissions. Nitrous oxide, which is a greenhouse gas, is formed in variable amounts, at levels up to 25 percent of the NO_x reduced.

SNCR-SCR Hybrids, in theory, would require small catalyst volumes and result in good NO_x removal efficiencies with little ammonia slip. This concept has been demonstrated on gas-fired boilers in southern California. Proper mixing of unreacted reagent (urea or ammonia) and NO_x before entering the catalyst bed may be difficult to achieve.

Fuel Switching refers to the conversion of a coal-fired boiler to natural gas firing. Some coal-fired boilers have gas-firing capabilities; others must be modified to burn gas. These modifications may be made in a way that retains the ability of the boiler to fire coal. Modified boilers may be used for year-round gas firing or merely for seasonal gas firing.

Fuel switching is generally applicable to pulverized coal boilers. The difficulty of the required retrofit will vary, with burner modifications required in some cases. If no gas hook-up exists, supply lines must be extended and connected to the boiler.

Baseline emissions reductions achievable through fuel switching are 45 percent on wall-fired boilers (0.9 lb/MMBtu controlled to 0.5 lb/MMBtu) and 55 percent on tangentially fired boilers (0.7 to 0.3 lb/MMBtu). Equivalent or greater reductions may be possible for cyclone boilers. Substituting natural gas for coal has the related advantage of reducing other air emissions, including SO_2, particulates and toxics. The extent of these accompanying reductions will depend upon the coal used and upon site-specific factors.

The high cost of natural gas relative to coal may make fuel switching more appropriate for seasonal rather than year-round operation. However, the higher fuel costs will be offset by reductions in operation and maintenance costs (e.g., those related to running pulverizers and storing coal) that occur when natural gas is burned. Sales of SO_2 allowances will also generate some revenue to counter the fuel price differential.

Natural gas availability and cost, particularly during the winter months, are primary impediments to fuel switching. Another impediment is reduced boiler efficiency when firing natural gas. Additional boiler heat loss that occurs during natural gas firing is partially offset by elimination of losses due to unburned carbon, to give an overall efficiency derate of 5-6 percent. Lower station power requirements compensate for a small portion of this derate.

Co-Firing of coal and natural gas will offer the benefits of gas switching in proportion to the extent of co-firing. Many coal-fired boilers are equipped for firing some gas through ignitors, warm-up guns or gas burners, and thus will incur no capital costs.

Co-firing of 5-40 percent gas with coal (heat input basis) has been demonstrated on a number of units. Emissions vary with the extent of co-firing, and typically are close to a weighted average of gas and coal emissions.

As is the case with fuel switching, co-firing has the added benefit of reducing emissions of pollutants other than NO_X. It shares the disadvantage of lowering plant efficiency.

Repowering is not performed primarily to control NO_X emissions from utility boilers and requires the longest outages to implement, but can provide the greatest emissions reductions. This is particularly true on the basis of emissions per unit of electrical output, in that repowered units are much more energy efficient. For example, replacement of a coal-fired boiler with 33 percent overall efficiency with a gas-fired combined cycle turbine that has 50-percent efficiency, can afford NO_X reductions of over 95 percent per kilowatt hour of electricity generated.

Repowering is applicable primarily to old utility boilers that are at the end of their service lives. New units typically will have much higher availabilities, and may have greater generating capacities than the units which they replace. The cost of repowering may be as high as \$500/kW, little of which should be accounted for as a NO_X control cost, but repowered units should have lower operating and maintenance costs.

EPA issued a guidance document in October 1993 suggesting that utility boilers repowering by May 31, 1999 be subject to different standards of cost effectiveness for RACT in the intervening period.

Potential National Emissions Reduction

Tables 6 and 7 summarize potential emissions reductions from utility boilers using the control techniques described above. Maximum potential emissions reductions for individual utility boilers should be greater than 90 percent, based on the installation of a combination of combustion and post-combustion controls. An average 75-percent reduction from the 1990 baseline, which could be achieved using SCR on some boilers and combustion modifications or SNCR on others, yields the estimates given in *Table 8*.

Costs and Cost Effectiveness

The costs of reducing NO_X emissions from utility boilers are unit-specific. Capital costs of electrical output will vary greatly with unit size as a result of economies of scale, and will also differ greatly based on retrofit difficulty. Busbar cost and removal cost effectiveness both vary inversely with boiler capacity factor, and will be lowest for baseload units and highest for rarely fired peaking units, given that capital costs must be allocated over the plant output and emissions.

The control capital costs identified in *Tables 9-11* are intended to be inclusive. That is, they include not only the direct costs of purchasing and installing air pollution control equipment, but also the costs of additional items beyond the scope of the air pollution control project (scope adders), which do not contribute directly to reductions in NO_X emissions. These scope adders may be important and necessary, such as new ignitors with retrofit low NO_X burners. They may include activities such as asbestos removal, which neither are part of the air pollution control equipment nor enhance its function, but must be undertaken in order to complete the air pollution control project. (Work completely unrelated to NO_X control system retrofits, that merely is performed at the same time, is not appropriately included in control costs.)

Capital and annual cost and cost effectiveness figures are shown as ranges, to account for likely variations in retrofit difficulty and emissions reduction. On large baseload units, cost effectiveness values are below \$1000/ton of NO_X removed in almost all cases. Specific capital costs for large (500 MW) baseload coal-fired boilers are \$10-\$30/kW for combustion controls, approximately \$10/kW for SNCR and fuel switching and \$50-\$80/kW for SCR. Removal costs range from \$150-\$300/ton for combustion controls, to \$300-\$900/ton for gas reburn, to \$500-\$1000/ton for post-combustion controls, to \$2500-\$3500 for fuel switching. On small peaking boilers, capital costs per unit of output and removal costs per ton of NO_X are higher. However, for smaller boilers with lower capacity factors, removal costs associated with less capital-intensive controls (e.g., fuel switching and SNCR) will increase less, making these technologies competitive with combustion controls on smaller units.

Capital costs for retrofit controls on oil- and gas-fired boilers are similar to those on coal-fired boilers. Given lower uncontrolled emissions, removal costs on these boilers are somewhat higher, up to about \$650/ton for combustion controls, and up to about \$1300/ton for post-combustion controls.

Costs per unit of electricity generated for controls on baseload boilers are a maximum of about 0.7¢/kWh for fuel switching, 0.35¢/kWh for SCR and 0.2¢/kWh for other alternatives. In fact, except on small peaking units, control costs should not exceed 1¢/kWh. These figures should be judged against a mean retail electricity cost of about 7¢/kWh, so that even stringent controls will add an average of less than 10 percent to consumer electricity costs.

The costs of alternative controls that have different NO_x removal efficiencies should not be compared directly, as it always will be cheaper to remove the first 10 percent of uncontrolled emissions than the last 10 percent.

In addition, boiler capacity factor and remaining useful life determine whether capital or operating costs are most significant in the selection of a control option. Low capital cost controls that have higher operating costs per unit of electrical output may be the least expensive, and hence, most appropriate choice for low capacity factor units. Conversely, higher capital cost controls with lower operating costs often will represent least-cost alternatives for high capacity factor units. Similar considerations govern remaining unit life; boilers that will be decommissioned or repowered in five years, for example, probably should be retrofitted with lower capital and higher operating cost controls.

Federal Rulemaking and/or Guidance Documents

EPA released an ACT document for utility boilers in May 1994 and will propose a New Source Performance Standard by a court-ordered deadline of August 31, 1994; this standard is to be promulgated by April 30, 1995.

EPA also released a rule covering utility boiler NO_x emissions under the acid rain provisions (Title IV) of the Clean Air Act Amendments of 1990. According to this rule, the 169 dry-bottom wall-fired and tangentially fired boilers that are also subject to the Title IV Phase I sulfur dioxide rules must meet NO_x emissions limits of 0.50 lb/MMBtu (wall-fired) and 0.45 lb/MMBtu (tangentially fired) by January 1, 1995. These limits, which are drawn from the CAAA, are based on the presumed performance of low NO_x burners in combination with advanced or separated overfire air. In fact, utilities that have implemented these technologies and cannot meet the limits will qualify for an alternative emissions limitation. Further, utilities that are unable to install low NO_x burners and overfire air by January 1, 1995, without an adverse impact on electricity production may apply for a 15-month extension of the compliance deadline. Averaging emissions among boilers is offered as a strategy for meeting the 0.50 lb/MMBtu and 0.45 lb/MMBtu limits.

According to the CAAA, EPA must promulgate limits for the remaining 539 dry-bottom wall-fired and tangentially fired boilers, as well as for approximately 300 boilers of all other types, by January 1, 1997.

For further information on the ACT, contact Bill Neuffer, U.S. Environmental Protection Agency, Emission Standards Division (MD-13), Research Triangle Park, NC 27711 (telephone: 919/541-5435). For further information on the acid rain rule, contact Peter Tsirigotis, U.S. Environmental Protection Agency, Acid Rain Division (6204J), 401 M Street, SW, Washington, DC 20460 (telephone: 202/233-9620).

State and Local Control Efforts

STAPPA/ALAPCO and NESCAUM adopted recommended NO_x emission limits for utility boilers in 1992. All states containing ozone nonattainment areas were to have promulgated NO_x RACT limits by November of that year. Typical RACT limits for dry-bottom pulverized-coal-fired boilers, as summarized in *Table 12*, fall in the 0.38-0.5 lb/MMBtu range. Limits for wet-bottom boilers are 1.0 lb/MMBtu if wall-or tangentially fired, and 0.43-0.6 if cyclone. The corresponding range for oil is 0.25-0.3 lb/MMBtu, while gas-fired boilers have a limit of 0.2 lb/MMBtu in almost all cases, except cyclone boilers, which have emission limits ranging up to 0.43 lb/MMBtu for gas and oil.

Retrofit NO_x emission limits adopted in California are much more stringent. In the South Coast (Los Angeles) and Ventura County Air Quality Management Districts, utility boilers must meet phased-in emission limits equivalent to 0.01-0.02 lb/MMBtu. The affected boilers principally burn natural gas. In the Bay Area Air Quality Management District (San Francisco), boilers must meet emission limits of 0.14-0.21 and 0.37-0.61 lb/MMBtu for gas and non-gaseous fuel-firing, respectively, in 1995. Limits to be phased in from 2000 to 2004 are 0.012-0.035 and 0.031-0.13 lb/MMBtu, respectively, for gas and non-gaseous fuels. During the ozone season, burning non-gaseous fuels is limited to emergencies.

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Figure 1

Schematic Diagram of Pulverized-Coal-Fired Utility Boiler

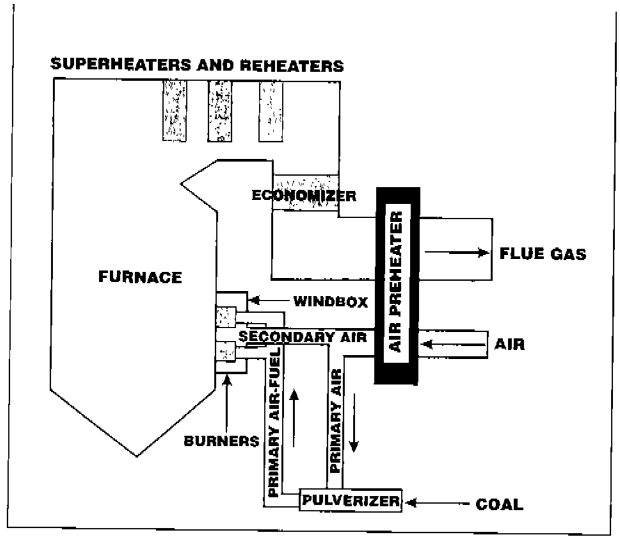

Figure 2

Schematic Diagram of SNCR and SCR Component Locations in Utility Boilers

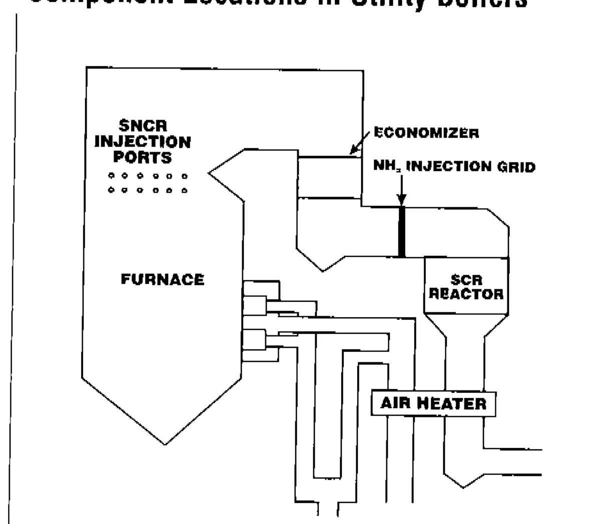

Table 1

Uncontrolled Utility Boiler Emissions

	Uncontrolled NO_x Emissions			
	Coal		Oil/Gas	
Boiler Type	Input Basis (lb/MMBtu)	Output Basis (lb/MWh)	Input Basis (lb/MMBtu)	Output Basis (lb/MWh)
Wall-Fired	0.9	8.5	0.5	4.7
Tangentially Fired	0.7	6.6	0.3	2.8
Cyclone	1.5	14	—	—
Stoker	0.5	4.7	—	—

Source: EPA, May 1994.

Table 2

Estimated NO_x Emissions from Utility Boilers

Fuel	Number of Boilers	National Emissions (tons/year)
Coal	1,190	5,656,000
Oil/Gas	2,280	724,500
Other	240	34,000
Total	3,710	6,414,500

Source: EPA, AIRS Facility Subsystem, July 1993.

Table 3

Relative Populations of Coal-Fired Utility Boilers

	Percentage of Each Boiler Type	
Boiler Type	By Number	By Capacity
Wall-Fired	69.2%	70.9%
Tangentially Fired	11.7%	12.3%
Cyclone	7.4%	15.2%
Stoker	10.8%	1.4%
Atmospheric Fluidized-Bed Combustion	0.8%	0.1%

Source: EPA, AIRS Facility Subsystem, July 1993.

Table 4

Estimated Number of Coal-Fired Utility Boilers and Their NO_x Emissions

Boiler Type	Number of Boilers	National Emissions (tons/year)
Wall-Fired	820	4,011,500
Tangentially Fired	139	696,900
Cyclone	88	861,700
Stoker	128	77,200
Atmospheric Fluidized-Bed Combustion	10	8,400
Total	1,185	5,655,700

Source: EPA, AIRS Facility Subsystem, July 1993.

Table 5

Fossil-Fuel-Fired Electric Generation Facilities

State	Plants	NO_x Emissions (tons/year)	Percent of Total Stationary Source NO_x Emissions
Alabama	11	256,000	78%
Alaska	8	14,800	64%
Arizona	137	69,100	63%
Arkansas	5	64,800	64%
California	14	12,100	26%
Colorado	18	86,700	74%
Connecticut	7	25,300	61%
Delaware	5	24,400	53%
District of Columbia	1	600	42%
Florida	44	299,200	89%
Georgia	14	232,500	76%
Hawaii	15	26,500	74%
Illinois	29	412,000	75%
Indiana	27	441,000	82%
Iowa	22	77,500	76%
Kansas	27	106,600	51%
Kentucky	21	303,500	91%
Louisiana	25	120,900	29%
Maine	9	6,600	19%
Maryland	14	118,200	83%
Massachusetts	21	93,800	85%
Michigan	3	2,100	15%
Minnesota	18	86,900	60%
Mississippi	10	41,400	55%
Missouri	24	286,500	89%
Montana	4	47,400	75%
Nebraska	10	69,800	85%
Nevada	6	61,100	99%
New Hampshire	11	25,000	89%
New Jersey	16	71,900	50%
New Mexico	8	61,400	46%
New York	36	166,200	67%
North Carolina	20	191,400	64%
North Dakota	9	114,200	91%
Ohio	32	499,600	75%
Oklahoma	14	69,400	37%
Oregon	2	700	6%
Pennsylvania	35	457,100	78%
Rhode Island	3	1,000	62%
South Carolina	12	89,100	64%
South Dakota	3	14,400	84%
Tennessee	7	239,500	74%
Texas	71	396,400	41%
Utah	3	29,000	33%
Vermont	1	100	50%
Virginia	12	77,400	51%
Washington	10	24,200	45%
West Virginia	13	295,800	80%
Wisconsin	14	110,700	72%
Wyoming	7	87,800	70%
Total	893	6,409,600	

Source: EPA, AIRS Executive, January 28, 1994.

Table 6 ....

Potential Emissions Reductions, Coal-Fired Boilers

	NO_x Reduction Potential (%)			
Control	Wall	Tangential	Cyclone	Stoker
LEA	10-20	10-20	N/A	10-20
BOOS	10-20	10-20	N/A	N/A
OFA	10-25	15-30	N/A	5-10
LNB	40-50	20-25	N/A	N/A
LNB+OFA	50-70	30-50	N/A	N/A
FGR	N/A	N/A	N/A	20-45
Reburn	50-60	50-60	50-60	N/A
SCR	75-90	75-90	75-90	75-90
SNCR	30-60	30-60	30-60	30-60
Fuel Switching	40-75	40-75	50-75	N/A
Co-firing	variable	variable	N/A	N/A
Repowering	90+	90+	90+	90+

Source: EPA, March 1994 and May 1994.

Table 7 ....

Potential Emissions Reductions, Oil- and Gas-Fired Boilers

Control	NOx Reduction Potential (%)
LEA	10-25
BOOS	15-35
OFA	10-45
LNB	30-50
LNB+OFA	40-60
FGR	40-50
Reburn	50-60
SCR	80-95
SNCR	35-50

Source: EPA, May 1994.

Table 8 ....

Potential National Emissions Reduction[1]

Fuel	Potential Reduction (tons/year)
Coal	4,200,000
Oil/Gas	540,000
Total	4,740,000

[1]Assumes 75% overall reduction in uncontrolled emissions.

Table 9

Costs of NO_x Control Technologies for Pulverized Coal-Fired Utility Boilers[1,2]

Technology	Unit Size and Operation	Wall-Fired Total Capital Cost ($/kW)	Wall-Fired Busbar Cost (mills/kWh)	Wall-Fired Cost Effectiveness ($/ton)	Tangentially Fired Total Capital Cost ($/kW)	Tangentially Fired Busbar Cost (mills/kWh)	Tangentially Fired Cost Effectiveness ($/ton)
OFA[3]	100 MW peaking	13-18	1.84-2.47	1310-4390		See note 4 below	
	300 MW cycling	8-11	0.45-0.58	320-1030		See note 4 below	
	500 MW baseload	6-8	0.23-0.28	170-500		See note 4 below	
LNB[5]	100 MW peaking	41-57	5.59-7.61	1990-3380	18-25	2.48-3.32	1620-3030
	300 MW cycling	26-35	1.17-1.59	420-710	12-16	0.52-0.71	340-650
	500 MW baseload	20-28	0.45-0.61	160-270	10-13	0.20-0.27	130-240
LNB + OFA[3,5]	100 MW peaking	52-69	7.07-9.23	2040-3340	34-44	4.55-5.86	2310-3860
	300 MW cycling	31-41	1.38-1.85	440-700	20-26	0.88-1.14	470-780
	500 MW baseload	24-32	0.50-0.67	180-280	15-20	0.32-0.41	180-300
Reburn[5]	100 MW peaking	51-61	7.87-9.23	2650-3730	51-61	7.87-9.23	3410-4800
	300 MW cycling	33-39	2.52-2.81	850-1140	33-39	2.52-2.81	1090-1460
	500 MW baseload	27-32	1.60-1.71	540-690	27-32	1.60-1.71	700-890
SNCR[6]	100 MW peaking	14-18	3.30-3.85	1330-1940	14-18	3.06-3.61	1590-2340
	300 MW cycling	11-14	1.58-1.72	640-870	11-14	1.34-1.48	700-960
	500 MW baseload	9-12	1.28-1.33	520-670	9-12	1.04-1.10	540-710
SCR[7]	100 MW peaking	100-133	24.2-30.6	5750-8230	97-129	23.6-29.7	7200-10,300
	300 MW cycling	68-91	6.06-7.50	1440-2020	66-88	5.87-7.27	1790-2520
	500 MW baseload	57-76	2.67-3.23	640-870	55-73	2.56-3.10	780-1070
Fuel Switching[8]	100 MW peaking	16-20	9.17-9.61	3090-3880	16-20	9.17-9.61	3970-4990
	300 MW cycling	11-13	7.43-7.53	2500-3040	11-13	7.43-7.53	3220-3910
	500 MW baseload	9-10	7.17-7.17	2400-2900	9-10	7.14-7.17	3090-3726

[1]Peaking, cycling and baseload units have capacity factors of 0.1, 0.3 and 0.65, respectively.
[2]Costs in 1993 dollars.
[3]Source: Bechtel, April 1994.
[4]Overfire air normally is not available without a simultaneous low NO_x burner retrofit.
[5]Source: EPA, May 1994.
[6]Urea-based SNCR, with urea nitrogen to NO_x ratio of 1.5.
[7]Capital costs derived from Cochran et al. (11/93) and Burns and Roe (2/94). Assumes five-year catalyst life, $400/ft^3 catalyst cost, catalyst volume defined by 4000/hr space velocity and annual charge of 5% of total capital to cover maintenance, taxes, insurance and administration.
[8]Assumes 12-month fuel switching with a fuel cost differential of $0.87 and an SO_2 allowance cost of $200/ton.

Table 10

Costs of NO_x Control Technologies for Coal-Fired Cyclone and Stoker Utility Boilers[1,2]

		Cyclone			Stoker		
Technology	Unit Size and Operation	Total Capital Cost ($/kW)	Busbar Cost (mills/kWh)	Cost Effectiveness ($/ton)	Total Capital Cost ($/kW)	Busbar Cost (mills/kWh)	Cost Effectiveness ($/ton)
Reburn[3]	100 MW peaking	51-61	7.86-9.22	1590-2240		See note 4 below	
	300 MW cycling	33-39	2.51-2.80	510-680		See note 4 below	
	500 MW baseload	27-32	1.59-1.70	320-410		See note 4 below	
SNCR[5]	100 MW peaking	14-18	4.01-4.57	970-1380	14-18	2.82-3.37	2050-3060
	300 MW cycling	11-14	2.30-2.44	560-740	11-14	1.10-1.25	800-1130
	500 MW baseload	9-12	1.99-2.05	480-620	9-12	0.80-0.86	580-780
SCR[6]	100 MW peaking	107-142	25.7-32.5	3670-5260	95-126	23.1-29.2	9340-13,300
	300 MW cycling	73-97	6.54-8.09	930-1310	65-86	5.72-7.10	2310-3220
	500 MW baseload	61-81	2.96-3.56	420-580	54-72	2.47-3.00	1000-1360

[1]*Peaking, cycling and baseload units have capacity factors of 0.1, 0.3 and 0.65, respectively.*
[2]*Costs in 1993 dollars.*
[3]*Source: EPA, May 1994.*
[4]*Not available.*
[5]*Urea-based SNCR, with urea nitrogen to NO_x ratio of 1.5.*
[6]*Capital costs derived from Cochran et al. (1/93) and Burns and Roe (2/94). Assumes five-year catalyst life, \$400/ft^3 catalyst cost, catalyst volume defined by 4000/hr space velocity and annual charge of 5% of total capital to cover maintenance, taxes, insurance and administration.*

Table 11

Costs of NO_x Control Technologies for Oil- and Gas-Fired Utility Boilers[1,2]

		Wall-Fired			Tangentially Fired		
Technology	Unit Size and Operation	Total Capital Cost ($/kW)	Busbar Cost (mills/kWh)	Cost Effectiveness ($/ton)	Total Capital Cost ($/kW)	Busbar Cost (mills/kWh)	Cost Effectiveness ($/ton)
BOOS[3]	100 MW peaking	1	0.22	260-400	1	0.22	530-880
	300 MW cycling	<1	0.10	120-180	<1	0.10	240-400
	500 MW baseload	<1	0.09	110-160	<1	0.09	220-360
OFA[4]	100 MW peaking	13-18	1.91-2.54	2030-4060		See note 6 below	
	300 MW cycling	8-11	0.54-0.62	550-1030		See note 6 below	
	500 MW baseload	6-8	0.30-0.35	320-550		See note 6 below	
LNB[4]	100 MW peaking	38-53	5.11-7.13	4130-7400	16-23	2.29-3.17	3960-6400
	300 MW cycling	23-33	1.09-1.51	880-1560	11-15	0.55-0.74	950-1500
	500 MW baseload	19-26	0.43-0.59	350-610	9-12	0.25-0.33	440-660
LNB + OFA[4]	100 MW peaking	43-65	5.97-8.70	3950-7170	34-44	4.58-5.86	5560-8990
	300 MW cycling	26-39	1.15-1.73	880-1540	20-26	0.88-1.14	1160-1840
	500 MW baseload	20-30	0.42-0.63	390-650	15-20	0.32-0.41	470-740
FGR[3]	100 MW peaking	11-16	2.12-3.04	2210-3620	11-16	2.12-3.04	3680-6040
	300 MW cycling	7-10	0.30-0.46	570-900	7-10	0.30-0.46	960-1500
	500 MW baseload	6-8	0.11-0.17	240-370	6-8	0.11-0.17	400-620
SNCR[5]	100 MW peaking	13-17	2.68-3.19	2160-3320	13-17	2.44-2.95	3390-5110
	300 MW cycling	10-13	1.06-1.19	860-1240	10-13	0.82-0.95	1110-1650
	500 MW baseload	9-11	0.78-0.83	630-870	9-11	0.54-0.60	730-1030
SCR[7]	100 MW peaking	57-76	13.4-17.0	5400-7730	56-74	13.0-16.5	8750-12,500
	300 MW cycling	39-52	3.23-4.06	1310-1840	38-51	3.10-3.91	2090-2960
	500 MW baseload	33-43	1.44-1.76	580-800	32-42	1.35-1.67	910-1260

[1]Peaking, cycling and baseload units have capacity factors of 0.1, 0.3 and 0.65, respectively.
[2]Costs in 1993 dollars.
[3]Source: EPA, December 1992.
[4]Source: EPA, May 1994.
[5]Overfire air normally is not available without a simultaneous low NO_x burner retrofit.
[6]Urea-based SNCR, with urea nitrogen to NO_x ratio of 1.5.
[7]Capital costs derived from Cochran et al. (1/93) and Burns and Roe (2/94). Assumes seven-year catalyst life, $400/ft^3 catalyst cost, catalyst volume defined by 9000/hr space velocity and annual charge of 5% of total capital to cover maintenance, taxes, insurance and administration.

Table 12

Selected Utility NO_x RACT Limits (lbs NO_x/MMBtu)

Jurisdiction/Fuel Type		Boiler Configuration: Tangential	Wall or Face	Cyclone	Stokers
STAPPA/ALAPCO[1]					
	gas only	0.20	0.20		
	gas/oil	0.25	0.25	0.43	
	coal, wet-bottom	1.00	1.00	0.55	
	coal, dry-bottom	0.38	0.38		0.40
NESCAUM[2]					
	gas only	0.20	0.20		
	gas/oil	0.25	0.25	0.43	
	coal, wet-bottom	1.00	1.00	0.55	
	coal, dry-bottom	0.38	0.43		0.30
Connecticut[3]					
	gas only	0.20	0.20	0.43	
	residual oil	0.25	0.25	0.43	
	other oil	0.20	0.20	0.43	
	coal	0.38	0.38	0.43	
Delaware[3]					
	gas only	0.20	0.20		
	gas/oil	0.25	0.25	0.43	
	coal, dry-bottom	0.38	0.38		0.40
Louisiana[3]					
	gas only	0.20	0.10-0.28		
	oil	0.20	0.30		
	coal	0.45	0.50		
Massachusetts					
	gas only	0.20	0.20		
	gas/oil		0.28		
	coal, dry-bottom	0.38	0.45		
New Jersey					
	gas only	0.20	0.20	0.43	
	gas/oil	0.20	0.28	0.43	
	coal, wet-bottom	1.00	1.00	0.60	
	coal, dry-bottom	0.38	0.45	0.55	
New York[3]					
	gas only	0.20	0.20		
	gas/oil	0.25	0.25	0.43	
	coal, wet-bottom	1.00	1.00	0.60	
	coal, dry-bottom	0.42	0.45		0.30
Ohio					
	gas only	0.20	0.30		
	gas/oil	0.20	0.30		
	coal, wet-bottom		1.00		
	coal, dry-bottom	0.45	0.50		0.40-0.50
Rhode Island					
	gas only	0.20	0.20	0.20	
	oil	0.25	0.25	0.25	
Texas					
	oil only	0.30	0.30	0.30	
	gas/oil	0.20-0.26	0.20-0.26	0.20-0.26	
	coal	0.38	0.43		

[1]The STAPPA/ALAPCO limits are recommendations. Phase II recommended limits are 0.05 (gas/oil) and 0.20 (coal).
[2]The NESCAUM limits are recommendations. Phase II recommended limits are 0.1 (gas/oil) and 0.2 (coal).
[3]These state limits are based on boiler size or type, irrespective of the end use. Limits are for the largest size boiler specified.

Industrial and Commercial Boilers

SUMMARY

Industrial and commercial boilers produce steam or heat water for use in industrial processes or space heating. Industrial boilers that range in size up to 1500 MMBtu/hr are common in the paper, chemical, petroleum and food production industries. Commercial boilers, with typical heat water inputs of below 10 MMBtu/hr, are used to heat offices, hospitals, schools, hotels and similar facilities.

Industrial and commercial boilers have three basic heat transfer configurations. Watertube boilers, that commonly have a heat input of 10-250 MMBtu/hr, transfer heat from an open furnace to water flowing through tubes, and may have designs similar or identical to utility boilers. Firetube boilers, with typical heat inputs of 1-30 MMBtu/hr, contain hot combustion gas in tubes that are immersed in a water basin to which heat is transferred. Cast iron boilers, which are the most common, are the smallest, with a median heat input below 1 MMBtu/hr, direct hot combustion gases through sections of heat transfer tubes. Most industrial and commercial boilers are packaged (shop-fabricated); only the largest (150+ MMBtu/hr) watertube boilers are field-erected. Controls may be installed easily on the less compact field-erected boilers.

Oil and natural gas are the most common fuels used in industrial boilers. These yield uncontrolled NO_x emissions ranging from about 0.1-0.3 lb/MMBtu (natural gas and distillate oil) to about 0.2-0.4 lb/MMBtu (residual oil). Coal is also used, and produces uncontrolled emissions of 0.5-0.9 lb/MMBtu from wall- and tangentially fired boilers and 0.2-0.6 lb/MMBtu from stokers.

Many of the NO_x controls used on utility boilers also are applicable to industrial and commercial boilers, with appropriate modifications to account for differences in size and design. Combustion modifications, including low excess air, overfire air, low NO_x burners, water/steam injection and flue gas recirculation, provide emissions reductions of 5-60+ percent. Post-combustion controls and selective catalytic and noncatalytic reduction have been installed on a number of boilers and provide emissions reductions of 30-90+ percent.

Control cost effectiveness for coal-fired industrial watertube boilers is approximately \$1000-\$2000 per ton of NO_x removed (see *Tables 7 and 8*). For field-erected and packaged oil- and gas-fired watertube boilers, cost

effectiveness values span a wider range, from below \$1000/ton to \$4000/ton. Firetube boiler NO_X control cost effectiveness is highest, at \$3000-\$11,000/ton. As for other sources, unit removal costs are highest for small, "clean" boilers and lowest for large, "dirty" ones.

Description of Source

Industrial and commercial boilers are used to produce steam or heat water for space and process heating and for the generation of mechanical power and electricity. In some cases, these boilers will have a dual function, such as the cogeneration of steam and electricity. The largest uses of industrial and commercial boilers by capacity are in paper, chemical, food production and petroleum industry processes. Based on boiler population, however, the largest single use of industrial and commercial boilers is space heating.

Industrial Boilers generally are smaller than utility boilers. While some are as large as 1500 MMBtu/hr heat input (corresponding approximately to a 150 MW utility boiler), boiler sizes extend down to 0.4 MMBtu/hr, with typical size units ranging from 10-250 MMBtu/hr. Industrial boilers generate steam for driving blowers and compressors and other equipment, for plant heating, for heating and cooling chemical reactors, for cooking and for cleaning. This steam normally is at lower temperatures and pressures than that produced by large utility boilers.

In addition to other applications, industrial boilers are used in oil production, particularly in California. Thermally enhanced oil recovery steam generators produce wet steam that is injected into wells to heat heavy oil in the ground, thus reducing its viscosity and promoting flow to the wells. These boilers normally have a capacity of 20-60 MMBtu/hr and are shop-assembled.

Commercial Boilers, which include the subcategory of institutional boilers, are normally used to produce steam and heat water for space heating in offices, hotels, apartment buildings, hospitals, schools and similar facilities. Commercial boilers typically have heat inputs below 10 MMBtu/hr, with most cast iron boilers (see *Boiler Designs*) having heat inputs below 0.4 MMBtu/hr.

Overall, industrial and commercial boilers are quite small, with 80 percent of the population smaller than 15 MMBtu/hr. On the other hand, large boilers account for a significant fraction of the total steam-generating capacity.

Over 80 percent of industrial and commercial boilers burn oil or gas, and over 90 percent of the boiler capacity is based on these fuels. (Oil refers to either distillate or Number 2 oil, which normally contains less than 0.01 percent nitrogen, or residual or Number 6 oil, which contains up to 6.7 percent nitrogen. Given its lower cost, Number 6 oil is used more frequently.) Most of the remaining boilers burn coal, with a small number burning biomass and other non-fossil fuels. (Boilers burning municipal solid waste are treated in a separate chapter of this document.)

Included among non-fossil-fuel-burning boilers are process gas boilers, which are fired with purge or exhaust gases from industrial processes. Use of process gas as a fuel allows both the recovery of residual heat value in the gas and the destruction of potential air pollutants. Notable among process gas boilers are carbon monoxide boilers at refineries. CO boilers burn catalytic cracker regenerator off-gas, which contains 5-10 percent CO, along with supplemental fuel.

Boiler Designs

Most industrial and commercial boilers are of three basic designs. In **Watertube Boilers** (*Figure 1*), heat is transferred from the furnace to circulating water in tubes. This is the design used in utility boilers. Watertube boilers can produce steam rapidly and can adapt to rapid changes in demand. Significant classes of watertube boilers, by number and capacity, are pulverized-coal-fired boilers, coal stokers and oil- and gas-fired boilers. There are a relatively small number of other types, such as fluidized-bed boilers. Steam generators for enhanced oil recovery are watertube boilers.

Firetube Boilers confine the hot combustion gases to tubes immersed in the boiler water. Firetube boilers are compact and low-cost. They are smaller on average than watertube boilers, normally having heat inputs of less than 50 MMBtu/hr. The susceptibility of the firetubes to structural failure places an upper limit on boiler size. Because firetube boilers respond less quickly to load variations, they are used in constant-load applications. Essentially all firetube boilers burn oil or gas.

Most significant among firetube boilers, by installed population and capacity, is the firebox boiler, which has an internal water-jacketed furnace. Firebox boiler heat input is normally less than 25 MMBtu/hr. Scotch marine boilers, with heat inputs up to 50 MMBtu/hr, have water-cooled furnaces in a horizontal inner shell in the water basin, with the firetubes running through the basin between this inner shell and the outer shell. In contrast to firebox and scotch designs, horizontal return tubular (HRT) boilers have separate furnaces made of firebrick, with the combustion gases that leave this furnace entering the firetubes. Typical HRT boiler heat input is up to 50 MMBtu/hr. Finally, while other common designs have horizontal firetubes, vertical firetube boilers have a water-cooled furnace from which the firetubes extend vertically to the stack. These are small boilers, normally 2.5 MMBtu/hr or less in capacity.

Cast Iron Boilers comprise over 80 percent of the industrial and commercial boiler population, but only approximately 10 percent of the total capacity, in that two-thirds of these are rated below 0.4 MMBtu/hr heat input, although some are as large as 10 MMBtu/hr. Cast iron boilers are used to produce low-pressure steam or hot water for domestic or small commercial operation, and operate by passing hot combustion gases through vertical sections of heat exchange tubes.

Table 1 identifies the breakdown of boilers by type and fuel. Industrial and commercial boilers may be classified further as field-erected or packaged.

Packaged boilers are shop-assembled and shipped as complete units. Shipping requirements imply that these are smaller boilers. All cast iron and almost all firetube boilers are packaged. Watertube boilers with capacities less than 150 MMBtu/hr are also typically shop-assembled; larger watertube boilers are erected in the field.

Emissions Per Unit Output

Uncontrolled NO_X emissions from industrial and commercial boilers, presented in EPA's ACT document based on data collected by EPA and other sources, are included in *Tables 2 and 3*. Typical uncontrolled emissions from natural-gas-fired watertube and firetube boilers are 0.1-0.3 lb/MMBtu, with firetube units at the bottom of this range. Distillate oil-fired boilers have similar emissions. Boilers burning higher-nitrogen-content residual oil have typical uncontrolled emissions of 0.2-0.4 lb/MMBtu, however, these emissions may be as high as 0.7 lb/MMBtu, in some cases. Finally, uncontrolled pulverized-coal-fired boiler and stoker emissions normally are 0.5-0.9 and 0.2-0.6 lb/MMBtu, respectively.

Little information is available on cast iron boiler emissions. Information collected by the Santa Barbara County Air Pollution Control District for commercial water heaters suggests that these emissions will be in the same range as emissions from comparably sized firetube boilers (e.g., 0.12 lb/MMBtu for a 75,000 Btu/hr gas-fired unit).

National Emissions Estimate

EPA estimates 1992 NO_X emissions from industrial boilers to be 3,523,000 tons, and from commercial/institutional boilers to be 304,000 tons, resulting in total emissions from this category of 3,827,000 tons per year. *Table 4* details the distribution of total NO_X emissions from industrial and commercial boilers emitting at least 100 tons/year by fuel type.

STAPPA/ALAPCO
Recommendation

▶ State and local agencies should consider regulating industrial and commercial boilers based upon their size. Boilers larger than 100 MMBtu/hr can be controlled utilizing the same technologies as those for utility boilers. Accordingly, industrial and commercial boilers could be controlled to levels of 0.15 lb/MMBtu or below for coal and 0.05 lb/MMBtu for oil and gas. Mid-sized boilers, such as those between 50-100 MMBtu/hr, can generally achieve limits of 0.10 lb/MMBtu for gas, 0.12 lb/MMBtu for distillate oil and 0.30 lb/MMBtu for residual oil using low NO_X burners, flue gas recirculation and fuel switching. Agencies should consider setting emission limits for mid-sized boilers burning coal at 0.38 lb/MMBtu. Smaller commercial and industrial boilers, less than 50 MMBtu/hr, should, at a minimum, be required to make annual "tune-ups" or adjustments to their boilers to minimize excess air. Additional reductions can be achieved from these boilers by setting limits similar to those imposed by several California local air quality management districts. Agencies should consider flexible control strategies consistent with EPA's Economic Incentive Program.

Geographic Distribution of Sources and Emissions

Table 5 contains a state-by-state breakdown of NO_X emissions from industrial boilers.

Available Control Strategies

Some of the strategies used for controlling NO_X emissions from utility boilers are also applicable to industrial and commercial boilers, particularly in the case of large watertube boilers. Differences in design, size and operation, however, strongly influence the applicability, performance and cost of these strategies. Further, some NO_x controls are unique to industrial and commercial boilers.

Two considerations affect the choice of NO_x controls for industrial and commercial boilers. First, the dependability of industrial boilers is critical. Interruption of steam flow may stop production and, in the worst case, result in damage to process equipment if materials solidify in unheated process lines.

A second consideration is that industrial and commercial boilers typically constitute a small part of the overall plant; therefore, particularly in smaller facilities, there will be no dedicated personnel to oversee boiler pollution control equipment.

For cast iron boilers, little information is available on retrofit controls. Low NO_x and radiant burner retrofits may be possible. Other possible strategies include requiring that replacement boilers be equipped with low NO_x burners or that they be electric rather than fossil-fuel-fired.

Load Reduction, or boiler derating, decreases combustion intensity, thus reducing thermal NO_x formation. Derating entails no capital or operating costs and is easily tested as a NO_x control alternative. In many cases, however, load reduction is not practical, given that industrial boiler load is normally determined by process steam needs. On the other hand, if plant-wide steam demand can be reduced through efficiency planning, then boiler derating will be a cost-effective emission control solution.

Low Excess Air, or reducing the amount of air available above the amount that is needed for complete combustion of fuel, lowers oxygen availability, thereby reducing NO_x emissions. Minimizing excess air is normally part of good combustion air management, in that it maximizes boiler thermal efficiency; therefore, this may not be available for implementation as a NO_x control strategy.

Operation of most boilers with low excess air is possible and this technique has been widely applied to watertube and firetube boilers. Implementation may be as simple as tuning the boiler using standard procedures. (A typical tune-up procedure is given in the California Air Resources Board's *Determination of Reasonably Available Control Technologies and Best Available Retrofit Technology for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters*, dated July 18, 1991.) On boilers with variable loads, O_2 or CO monitors may be needed to provide feedback to the combustion air flow controller. The cost of a system to monitor and automatically trim the oxygen level in a small watertube or firetube boiler will be on the order of \$10,000-\$20,000; the cost of a boiler tune-up is somewhat less than this. These costs would be offset by fuel savings resulting from increased boiler efficiency.

Excess oxygen is limited to no less than about 2-4 percent for oil and 0.5-3 percent for gas, depending on boiler and burner design. According to data collected for EPA and contained in the ACT document, controlled emissions from watertube and firetube boilers firing natural gas will be 0.07-0.3 lb/MMBtu at minimum excess air levels, corresponding to NO_x reductions of 5-35 percent from uncontrolled levels. Boilers burning distillate oil will have controlled emissions of 0.09-0.2 lb/MMBtu, while boilers burning residual oil will have controlled emissions of 0.15-0.45 lb/MMBtu; these emission levels correspond to 5-25 percent emissions reductions. For coal-fired units, controlled emissions are 0.2-0.5 lb/MMBtu and emissions reductions are 5-30 percent. Because lowering excess air increases boiler efficiency, emissions per unit of steam output decrease even more.

As excess air is reduced, emissions of CO and hydrocarbons may increase. Further, at very low excess air levels, flame instability may occur and accelerated corrosion may result from the creation of a reducing atmosphere inside the boiler.

Burners Out-of-Service (BOOS), in which all of the fuel is routed to a subset of the burners, while only air alone is input through the rest of the boilers, creates fuel-rich primary combustion zones. Limited oxygen in these zones lowers the peak flame temperature and creates reducing conditions, thus lowering both thermal and fuel NO_x emissions.

While taking burners out of service is inexpensive, its applicability is limited to larger boilers, as smaller packaged boilers often have only one burner. Oil- and gas-fired boilers with multiple burners are, therefore, amenable to this technique, provided that the burners remaining in service have sufficient firing capacity to avoid a derate. Fixed pulverizer-burner connections may preclude the use of BOOS on some coal-fired boilers.

Very limited data suggest potential emissions reductions of 10-30 percent using BOOS on industrial boilers burning pulverized coal, oil or gas.

Overfire Air entails reducing the flow of primary combustion air through the burners and injecting sufficient air to complete combustion through overfire air ports above the top row of burners.

In order for overfire air to be effective, there must be sufficient distance between the top row of burners and the furnace exit to provide enough residence time for completion of primary combustion before the overfire air is injected, and adequate time afterward for completion of combustion (and carbon burnout, in the case of solid fuels). The boiler geometry also must allow good mixing of overfire air with the products of primary combustion.

Small boilers in general, and firetube boilers in particular, often will not meet these criteria and, therefore, will not be amenable to the application of overfire air.

Overfire air retrofits require penetration of the boiler wall, which may affect structural integrity. On large, field-erected boilers, windbox modifications will be required. Retrofits on firetube boilers would typically require penetration of the water shell and, therefore, would not be feasible.

Emissions reductions of 20-40 percent have been demonstrated on small gas- and oil-fired boilers; on pulverized-coal-fired boilers reductions are 15-30 percent and on stokers, 5-30 percent.

An issue to be considered with respect to the use of overfire air is the possibility of increased emissions of CO and hydrocarbons and, in the case of coal-fired units, unburned carbon. The reducing atmosphere created in the fuel-rich primary combustion zone may also result in accelerated corrosion of the furnace. Grate corrosion and overheating may occur in stokers as primary air flow is diverted to overfire air ports.

Flue Gas Recirculation (FGR), a very common control on oil- and gas-fired industrial boilers, reduces NO_X emissions by diluting combustion air with inert flue gas, thus lowering the peak flame temperature. As is the case with water injection (discussed later in this chapter), the primary effectiveness of FGR is in reducing thermal NO_X. It is, therefore, useful for reducing emissions from boilers firing natural gas or low-nitrogen fuel oils, but not from boilers firing coal and high-nitrogen oils.

FGR systems are available for boilers with heat inputs as low as 5 MMBtu/hr, and have been installed on relatively large numbers of existing watertube and firetube boilers, but not on cast iron boilers. Retrofit requirements include ducting from the stack to the windbox, an FGR fan, flow control dampers and controls, if the boiler has a variable load. Depending upon the existing setup, other needs may include a new or modified windbox, combustion air fan and flame safeguard system. In cases where limited burner capacity would require a boiler derate, burner replacement may be necessary to maintain boiler output. When considering FGR, it is important to consider space limitations, which typically will increase the cost of the retrofit.

Despite a general lack of applicability to boilers burning high-nitrogen fuels, FGR can be an effective control for stokers. Its function in stokers is to allow a reduction in excess air levels below those that normally would result in excessive grate temperatures.

Controlled levels vary with the amount of flue gas recirculated. Flame stability problems at high gas flow rates through the burner limit the fraction of recirculated flue gas to about 15 percent when firing natural gas and 10-12 percent when firing oil. On natural-gas-fired packaged watertube and firetube boilers, controlled emissions of 0.05-0.10 lb/MMBtu are possible. Controlled NO_X levels of 0.1-0.2 lb/MMBtu are possible on similar oil-fired boilers.

Low NO_X Burners, which stage the introduction of air or fuel, lower the peak flame temperature and limit the oxygen level during primary combustion, reduce emissions of both thermal and fuel NO_X.

Low NO_X burners have been installed on many industrial and commercial boilers with both watertube and firetube designs and burning all fossil fuel types. On large, field-erected boilers, low NO_X burner technology developed for utility boilers may be applied. Retrofit low NO_X burners are available for most boilers.

Because air-staging low NO_X burners typically produce longer flames, their installation may result in flame impingement on furnace components at full load. In such cases, either the boiler must be derated or alternatives other than low NO_X burners must be selected.

The ease of retrofitting low NO_X burners on industrial and commercial boilers varies from case to case. For some boilers, plug-in replacement burners are available, and may be installed without modifying the boiler. On field-erected watertube boilers, modification of the boiler waterwall and windbox may be required, along with the installation of new controls, flame scanners and other components.

Controlled emissions achievable with low NO_X burners are 0.05-0.20 lb/MMBtu on gas-fired, 0.1-0.35 lb/MMBtu on distillate oil-fired, 0.1-0.6 lb/MMBtu on residual oil-fired and 0.3-0.5 lb/MMBtu on pulverized-coal-fired boilers.

Low NO_X burners must be optimized to avoid increases in CO, hydrocarbon and unburned carbon emissions, with accompanying losses in boiler thermal efficiency.

Radiant Burners pass premixed air and gaseous fuel through porous ceramic fiber tips which glow, with no flame, at 1800°F. Little thermal NO_X is formed at this low combustion temperature. A further advantage of radiant burners is that premixing allows the use of very low excess air levels, which helps to lower NO_X emissions further and provide fuel savings from reduced boiler heat loss.

Radiant burners may be installed on natural-gas-fired firetube and watertube boilers. (Radiant burners cannot fire liquid or solid fuels.) Limited radiant burner size means that this technology is suitable only for small and medium-sized boilers. Retrofit of these burners should not be complex; each burner is designed to occupy the same furnace volume as a conventional flame, while the burners use existing blowers and ignition and control systems. Radiant burners have been installed on a number of firetube and watertube boilers throughout the U.S.

Controlled radiant burner NO_x emissions are approximately 25 ppmv or 0.03 lb/MMBtu, which corresponds to an emissions reduction of 70-80 percent on firetube boilers and 80-90 percent on watertube boilers. Some newer radiant burners provide controlled emissions of 10 ppmv or lower.

Water/Steam Injection lowers the peak flame temperature and, secondarily, the oxygen concentration, through the injection of water (or, in some cases, steam) into the combustion zone.

Because water/steam injection is effective primarily for reducing thermal NO_x, it is applicable to gas- and distillate oil-fired boilers only. This technique will be less attractive on larger, high capacity factor boilers, or where water is relatively expensive, given the need to purchase large amounts of water. The difficulty and capital cost of retrofit water injection are relatively low. In some cases, the oil gun in a gas ring burner may be replaced with a water injection nozzle.

Control efficiency is a function of the amount of water injected. In principle, NO_x removal efficiencies greater than 70 percent are possible on natural-gas-fired boilers and greater than 40 percent on oil-fired boilers, but these efficiencies would require the injection of over one pound of water per pound of fuel. In addition to the cost of purchasing water, the amount injected is limited by thermal efficiency losses and also by increased CO emissions from lower temperature flames. Therefore, practical limits to water injection are 25-75 percent of the fuel feed rate on a weight basis, resulting in 25-50 percent removal efficiencies.

Fuel Switching from coal or residual oil to natural gas as the sole fuel can produce significant NO_x reductions. Baseline reductions on pulverized-coal-fired boilers are on the order of 65 percent, and on residual-oil-fired boilers, on the order of 40 percent.

Fuel switching should be generally applicable to industrial boilers, many of which already are equipped to fire gas. The higher cost of gas relative to coal should be offset somewhat by lower operating and maintenance costs. One impediment to switching from coal to gas would be the derate which commonly accompanies natural gas firing; boilers operated at maximum continuous load might be unable to meet steam generating requirements.

Selective Catalytic Reduction (SCR), the destruction of NO_x in a catalyst-promoted reaction with injected ammonia, was developed for utility boilers, but also is applicable to larger industrial watertube boilers. Installation on packaged watertube boilers can be difficult if the design of these boilers does not provide sufficient space for the catalyst reactor in a region of appropriate temperature. The application of SCR to firetube boilers may be problematic, given their low exit gas temperatures, but has been demonstrated commercially.

SCR typically will be the most expensive NO_x control alternative for industrial boilers. Retrofit of this technology requires the installation of ducting, a reactor and catalyst, an ammonia storage and injection system and appropriate controls. Relocation of the boiler economizer or air heater (or of other equipment in crowded industrial plants) to create room for the catalyst may add significantly to costs.

SCR has been installed on over 10 new industrial boilers in the U.S., as well as a larger number of new and existing boilers overseas, that burn a variety of fuels. These boilers are both field-erected and packaged.

The NO_x removal effectiveness of SCR is high, with emissions reductions of 80-90 percent readily achievable. Controlled emissions of less than 0.05 lb/MMBtu are possible on oil- and gas-fired boilers, and of less than 0.1 lb/MMBtu on coal-fired boilers.

While ammonia slip has been limited to levels well below 20 ppm in appropriately designed systems, ammonium bisulfate formation will still occur in boilers burning sulfur-containing fuels. This will entail more frequent cleaning of downstream components. Catalyst poisoning may be an additional concern on process boilers or boilers burning waste fuels, resulting in the need for catalyst replacement.

Selective Noncatalytic Reduction (SNCR) systems using both ammonia and urea to reduce NO_x to nitrogen have been installed on industrial boilers in the U.S. Urea-based NO_xOUT™ has been installed on several refinery gas/CO and coal-fired boilers in the U.S., including at least one packaged boiler. Ammonia-based Thermal DeNO_x is also operating on refinery gas-fired boilers.

SNCR is generally applicable to watertube boilers, although some may not provide sufficient flue gas residence times in the temperature range needed for completion of the ammonia/urea-NO_x reactions. Firetube boilers may not be amenable to SNCR, given the relatively low temperature in the firetubes and the difficulty of installing injection ports.

Retrofit of SNCR should be relatively simple and inexpensive, although boiler flow modeling will be needed to maximize NO_x removal and minimize ammonia slip, particularly at variable loads. Achievable emissions reductions will be in the 30-70 percent range, and will vary considerably with boiler design and uncontrolled NO_x levels.

Both urea- and ammonia-based SNCR produce ammonia slip, which is related to the desired NO_X reduction, and which may be maintained below 10-20 ppm with appropriate design, including the use of multiple injection levels on variable load boilers. The need to limit ammonia slip may constrain achievable emissions reductions; higher reductions in NO_X emissions normally will be attained with increased reagent injection. Further, chloride-containing fuels may lead to the occurrence of ammonium chloride plumes if slip is not limited.

In some cases, nitrous oxide, which does not contribute to ground-level ozone formation, but which is a greenhouse gas, may be produced by SNCR systems.

If sulfur-containing fuels are burned, unreacted ammonia will react with sulfur trioxide formed in the boiler to produce ammonium bisulfate, which will collect on the economizer and other downstream surfaces, necessitating additional maintenance.

Potential National Emissions Reduction

While many industrial and commercial boilers have heat inputs below 10 MMBtu/hr, larger units contribute disproportionately to total boiler capacity and, thus, to NO_X emissions. This is particularly true given higher heat release rates and consequent higher thermal NO_X formation in larger boilers. The application of a combination of controls on larger boilers could yield an overall 50-percent reduction in combined watertube and firetube NO_X emissions, based on the potential reductions summarized in *Table 6*. (No control of cast iron boiler emissions is assumed.)

Costs and Cost Effectiveness

Representative cost and cost effectiveness figures for controlling NO_X emissions from industrial and commercial boilers are given in *Tables 7 and 8*, as derived from EPA's ACT document and other relevant sources. Capital costs per unit of heat input vary considerably with boiler size, with costs highest for the smallest packaged boilers and lowest for the largest field-erected boilers. This variation in capital costs is reflected in removal costs per ton of NO_X.

On large (500-MMBtu/hr) coal-fired industrial boilers, capital costs range from approximately $2000 per MMBtu/hr heat input for overfire air and SNCR, to $6500/MMBtu/hr for low NO_X burners, to $12,000/ MMBtu/hr for SCR. (Expressed on an electric output equivalent basis, these figures would be $20, $65, and $120 per kW, respectively.) For combustion controls and SNCR, cost effectiveness is on the order of $1000/ton of NO_X and $2000/ton for SCR.

Capital costs on field-erected watertube boilers range from below about $200/MMBtu/hr for simple control strategies, such as low excess air, burners out-of-service and water injection, to $1000/MMBtu/hr for low NO_X burners, to $2000/MMBtu/hr for FGR, to $3000-$4000/MMBtu/hr for SCR and SNCR, to over $6000/MMBtu/hr for radiant burners. The cost effectiveness of combustion modifications is below $1000/ton in most cases, $2000-$4000/ton for FGR, and approximately $4000/ton for radiant burners. In fact, use of low excess air operation provides a positive net return, as it increases boiler thermal efficiency. The cost effectiveness of SCR and SNCR is typically $1000-$2000/ton and $2000-$4000/ton, respectively. Corresponding costs on smaller, packaged watertube boilers are somewhat higher.

Given their small size, typical control costs are highest on firetube boilers. Strategies such as low excess air and water injection have capital costs near $2500/MMBtu/hr for 10-MMBtu/hr boilers. Radiant burners cost near $4000/MMBtu/hr to install, and low NO_X burners and FGR are both near $6000/MMBtu/hr. Depending upon the fuel, control cost effectiveness will normally fall in the $3000-$11,000/ton range.

It should be noted that there will be considerable economies of scale on single-burner packaged boilers; costs will increase by perhaps 30 percent with a doubling of size for low NO_X burners and FGR. On field-erected units with multiple burners, economies of scale will not be as great.

Federal Rulemaking and/or Guidance Documents

EPA released an ACT for industrial, commercial and institutional boilers in March 1994.

On March 16, 1994, EPA issued a memorandum offering guidance on what constitutes cost-effective NO_X control technology for industrial sources. EPA's analysis is based on a requirement for controls comparable to those needed to meet the presumptive RACT limits for dry-bottom wall- and tangentially fired utility boilers. According to this analysis, states should consider, at a minimum, NO_X control technology with a cost effectiveness of $160-$1300/ton in their development of RACT requirements. Where technologies in the $160-$1300/ton range are inadequate to achieve emissions reductions of 30-50 percent (needed to meet presumptive utility boiler RACT limits), or to meet more stringent state limits, then states should apply higher cost effectiveness values in their NO_X RACT determinations.

For further information on the ACT, contact Bill Neuffer, U.S. Environmental Protection Agency, Emission

Standards Division (MD-13), Research Triangle Park, NC 27711 (telephone: 919/541-5435). For further information on the cost effectiveness guidance memorandum, contact John Silvasi, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 (telephone: 919/541-5666).

State and Local Control Efforts

Several states with ozone nonattainment areas have promulgated RACT limits for industrial boiler NO_x emissions. These limits are listed in *Table 9*, along with recommendations adopted by the Northeast States for Coordinated Air Use Management. Limits for coal-fired boilers are similar to the corresponding utility boiler limits. For gas-fired boilers, typical emission limits are in the 0.1-0.2 lb/MMBtu range, depending on boiler size and configuration. Limits for oil-fired boilers typically are 0.2-0.3 lb/MMBtu, although some rules in northeastern states specific to distillate oil follow the NESCAUM recommendation of 0.12 lb/MMBtu for that fuel.

Rules in California are much more stringent (see *Table 10*), in that they tend to represent "best available" technology. Typical California district limits are 0.036 lb/MMBtu for gas-fired boilers and 0.05 lb/MMBtu for other boilers. Further, these limits commonly refer to all boilers with heat input above 5-10 MMBtu/hr, as opposed to 50-100 MMBtu/hr in other states.

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Figure 1

Industrial and Commercial Boiler Heat Transfer Configurations

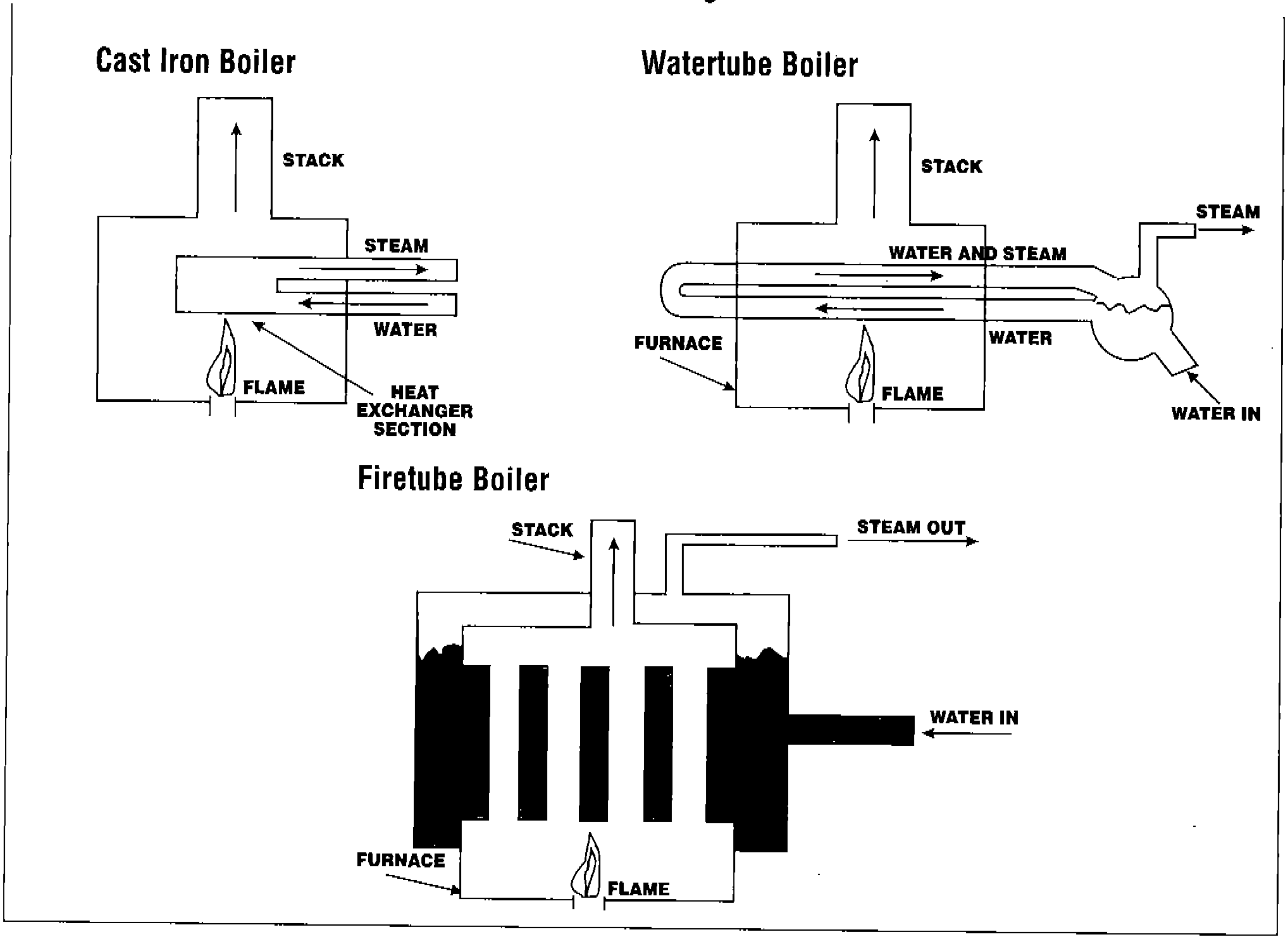

Table 1

Common Industrial and Commercial Boiler Designs and Fuels

Boiler Design and Fuel	Fraction of Boiler Population (%)	Fraction of Boiler Capacity (%)
Cast Iron, Gas/Oil	72.0	9.6
Cast Iron, Coal	9.9	1.3
Firetube, Gas/Oil Firebox	6.5	48.0
Firetube, Gas/Oil Scotch	4.8	4.6
Watertube, Gas/Oil	2.3	24.0
Firetube, Gas/Oil HRT	1.5	1.5
Firetube, Gas/Oil Vertical	1.0	<1.0
Watertube, Coal Stoker	<1.0	5.0
Watertube, Pulverized Coal	<1.0	2.5
Watertube, Steam Generator	Unknown	Unknown

Source: EPA, March 1994.

Table 2

Typical Uncontrolled NO_x Emissions from Firetube Boilers

Fuel	Uncontrolled Emissions (lb/MMBtu)
Natural Gas	0.10
Distillate Oil	0.17
Residual Oil	0.31

Source: EPA, March 1994.

Table 3

Typical Uncontrolled NO_x Emissions from Watertube Boilers

Fuel	Boiler Type or Size	Uncontrolled Emissions (lb/MMBtu)
Natural Gas	Packaged (50 MMBtu/hr)	0.14
	Field-Erected (150 MMBtu/hr)	0.23
	Enhanced Oil Recovery Boiler	0.12
Distillate Oil	Packaged (50 MMBtu/hr)	0.13
	Field-Erected (150 MMBtu/hr)	0.21
Residual Oil	Packaged (50 MMBtu/hr)	0.36
	Field-Erected (150 MMBtu/hr)	0.38
Crude Oil	Enhanced Oil Recovery Boiler	0.46
Coal	Wall-Fired	0.69
	Tangentially Fired	0.61
	Spreader Stoker	0.53
	Overfeed Stoker	0.29

Source: EPA, March 1994.

Table 4

Estimated NO_x Emissions from Industrial and Commercial Boilers Emitting At Least 100 Tons NO_x Per Year

Fuel	Number of Boilers	National Emissions (tons/year)
Coal	2,060	438,000
Oil	5,500	183,000
Gas	9,920	752,000
Other	2,360	231,000
Total	19,840	1,604,000

Source: EPA, AIRS Executive.

Table 5

Distribution of Industrial Boiler NO_x Emissions by State

State	1991 Emissions (tons)
Alabama	65,400
Arizona	47,400
Arkansas	46,300
California	182,800
Colorado	38,400
Connecticut	5,600
Delaware	10,100
District of Columbia	500
Florida	31,500
Georgia	51,200
Idaho	12,900
Illinois	129,800
Indiana	126,300
Iowa	28,300
Kansas	109,300
Kentucky	68,300
Louisiana	318,700
Maine	12,500
Maryland	18,200
Massachusetts	14,000
Michigan	77,700
Minnesota	26,800
Mississippi	74,400
Missouri	23,200
Montana	13,400
Nebraska	8,100
Nevada	3,200
New Hampshire	6,400
New Jersey	25,500
New Mexico	79,900
New York	57,900
North Carolina	54,300
North Dakota	21,200
Ohio	93,500
Oklahoma	118,100
Oregon	15,900
Pennsylvania	95,700
Rhode Island	4,300
South Carolina	39,600
South Dakota	3,200
Tennessee	62,000
Texas	1,096,800
Utah	30,400
Vermont	600
Virginia	56,000
Washington	30,000
West Virginia	53,000
Wisconsin	45,400
Wyoming	69,800
National	3,601,800

Source: EPA, "Regional Interim Inventories (1987-1991): Volume II: Emission Summaries," EPA-454/R-93-021b, May 1993.

Table 6

Applicability of and Potential Emissions Reductions Possible with Various Options for Controlling NO_x Emissions from Industrial and Commercial Boilers

	Potential NO_x Reduction							
	Coal-Fired Boilers		Oil-Fired Boilers			Gas-Fired Boilers		
	Watertube		Watertube		Firetube	Watertube		Firetube
Control	PC	Stoker	Field-Erected	Packaged		Field-Erected	Packaged	
Low Excess Air	5-30	5-30	5-25	5-25	5-25	5-35	5-35	5-35
Burners Out-of-Service	10-30	N/A	10-30	N/A	N/A	10-30	N/A	N/A
Overfire Air	15-30	0-30	25	20-40	N/A	35	20-40	N/A
Low NOx Burners	50	N/A	45	45	45	55	50	50
Radiant Burners	N/A	N/A	N/A	N/A	N/A	90	80	70-80
Flue Gas Recirculation	N/A	20-45	15-30	15-30	15-30	50-65	50-65	50-65
Water Injection	N/A	N/A	15-35	15-35	15-35	25-50	25-50	25-50
Natural Gas Reburn	60	N/A	80	N/A	N/A	N/A	N/A	N/A
Selective Catalytic Reduction	80-90	80-90	80-90	80-90	N/A	80-90	80-90	N/A
Selective Noncatalytic Reduction	30-70	30-70	30-70	30-70	N/A	30-60	30-60	N/A
Fuel Switching	65	N/A	40	60	40-65	N/A	N/A	N/A

Source: EPA, March 1994.

Table 7

Cost and Cost-Effectiveness of Controlling NO_x Emissions from Coal-Fired Industrial Boilers[1]

	Pulverized Coal			Stoker		
Control	Capital Cost ($/MMBtu/hr)	Annual Cost ($/MMBtu/hr/yr)	Cost Effectiveness ($/ton)	Capital Cost ($/MMBtu/hr)	Annual Cost ($/MMBtu/hr/yr)	Cost Effectiveness ($/ton)
Overfire Air[2]	2060	298	580-1450		See note 3 below	
Low NOx Burners[2]	6500	779	760-950		See note 3 below	
Selective Catalytic Reduction[4]	12400	2750	1790-2030	11800	2620	1980-2230
Selective Noncatalytic Reduction[2]	1570	784	870-1090	1570	687	940-1170

[1]*Annual cost and cost effectiveness for 0.6 capacity factor, 500 MMBtu/hr boilers; costs in 1993 dollars.*
[2]*EPA, March 1994.*
[3]*Not Applicable.*
[4]*Capital costs derived from Cochran et al. (11/93) and Burns and Roe (2/94). Annual costs and cost effectiveness assume five-year catalyst life, $400/ft^3 catalyst cost, catalyst volume defined by 4000/hr space velocity and annual charge of 5% of total capital to cover maintenance, taxes, insurance and administration.*

Table 8

Costs of Controlling NO_x Emissions from Oil- and Gas-Fired Industrial and Commercial Boilers[1]

Control	Residual Oil			Distillate Oil			Natural Gas		
	Capital Cost ($/MMBtu/hr)	Annual Cost ($/MMBtu/hr/yr)	Cost Effectiveness ($/ton)	Capital Cost ($/MMBtu/hr)	Annual Cost ($/MMBtu/hr/yr)	Cost Effectiveness ($/ton)	Capital Cost ($/MMBtu/hr)	Annual Cost ($/MMBtu/hr/yr)	Cost Effectiveness ($/ton)
Firetube (10 MMBtu/hr)									
LEA[2]	2500	372	2280-4570	2500	270	3020-6040	2500	387	7360-14700
LNB[3]	5850	1190	2910-3640	5850	1190	5310-6640	5850	1190	9030-11300
RB[4]		See note 5 below			See note 5 below		3600	1060	5020-5730
FGR[3]	6110	1480	6040-12100	6110	1480	11000-22000	6110	1480	9360-11200
WI[2]		See note 2 below		2500	744	5550-8330	2500	627	5960-7950
Packaged Watertube (50 MMBtu/hr)									
LEA[2,6]	500	-33	<0	500	-136	<0	500	-18	<0
LNB[3]	2320	470	990-1240	2320	470	2750-3440	2320	470	2560-3200
RB[4]		See note 5 below			See note 5 below		6730	1960	6670-7630
FGR[3]	4160	1000	3530-7060	4160	1000	9780-19600	4460	1000	4540-5450
WI[2]	500[2]			500	338	3900-4950	500	221	1500-2000
SCR[2]	6420	1560	2070-2360	6420	1510	5200-5890	6420	1510	4830-5480
SNCR[2]	3300	1040	2190-2740	3300	862	5040-6310	3300	869	4720-5910
Field-Erected Watertube (150 MMBtu/hr)									
LEA[2,6]	167	-101	<0	167	-203	<0	167	-86	<0
BOOS[2]	167	101	400-680	167	152	750-1250	167	94	620-1030
LNB[3]	1200	243	490-610	1200	243	600-750	1200	243	800-1010
RB[4]		See note 2 below			See note 2 below		6520	1900	3500-3940
FGR[3]	2070	505	1690-3370	2070	505	2060-4130	2070	505	1390-1670
WI[2]		See note 2 below		167	271	1110-1660	167	154	640-850
SCR[2]	3770	1030	1290-1480	3770	1020	1560-1780	3770	996	2060-2350
SNCR[2]	3300	1050	2100-2630	3300	997	2450-3060	3300	937	3100-3880

[1] *Annual cost and cost effectiveness for 0.6 capacity factor; costs in 1993 dollars.*
[2] *Source: EPA, March 1994.*
[3] *Source: CARB, April 29, 1987.*
[4] *Source: Santa Barbara County, December 1991.*
[5] *Not applicable.*
[6] *Improved energy efficiency achieved using low excess air results in lower fuel costs and thus a net return on control strategy.*

Table 9

Selected Industrial Boiler NO_x RACT Limits[1]

Jurisdiction/Fuel Type	Emission Limit (lb/MMBtu) 50-100 MMBtu/hr	100-250 MMBtu/hr
NESCAUM[2]		
gas	0.10	0.20
distillate oil	0.12	0.25-0.43
residual oil	LNB+FGR	0.25-0.43
coal, dry-bottom		0.30-0.43
coal, wet-bottom		0.55-1.00
Connecticut		
gas only	0.20-0.43	0.20-0.43
residual oil	0.20-0.43	0.20-0.43
other oil	0.25-0.43	0.25-0.43
coal	0.38-0.43	0.38-0.43
Delaware		
gas only	LNB+FGR	0.20
gas/oil	LNB+FGR	0.25-0.43
coal, dry-bottom		0.38-0.40
Louisiana[3]		
gas only	0.10-0.28	
gas/oil	0.20-0.30	
coal	0.45-0.50	
Massachusetts		
gas only		0.20
gas/oil		0.30-0.40
coal, dry-bottom		0.38-0.45
New Jersey		
gas only	0.1	0.20-0.43
gas/oil		0.20-0.43
distillate oil	0.12	
other liquid fuels	0.3	
coal, dry-bottom	0.38-0.55	0.38-0.55
coal, wet-bottom	0.55-1.00	0.60-1.00
New York		
gas	0.10	
distillate oil	0.12	
residual oil	0.30	
Ohio		
gas only		0.20
gas/oil		0.30
coal, dry-bottom		0.40-0.50
coal, wet-bottom		1.00
Rhode Island		
gas	0.10	
distillate oil	0.12	
residual oil	LNB+FGR	
Texas		
gas only		0.10-0.28
liquid fuel		0.30

[1]In addition to fuel and boiler type, many jurisdictions differentiate limits based on boiler size, level of heat release and preheated air temperature. Where different limits are set based on these distinctions, this table presents ranges. Standards for boilers less than 50 MMBtu/hr typically require an "annual tune-up" or "appropriate adjustment of combustion procedures."
[2]NESCAUM limits are recommendations.
[3]Louisiana limits apply to boilers ≥80 MMBtu/hr.

Table 10

Industrial Boiler Retrofit NO_x Limits in California

Fuel	Emission Limit (lb/MMBtu)	Boiler Size (MMBtu/hr)
Bay Area		
gas	0.036	≥10
other	0.052	≥10
San Joaquin		
gas	0.036	≥10
liquid	0.052	≥10
South Coast		
gas	0.037	≥2, <5
liquid	0.050	≥5
other	0.037	≥40
Ventura	0.050	≥5
California Air Resources Board: RACT Guidance		
gas	0.084	≥5
other	0.150	≥5
California Air Resources Board: BARCT Guidance		
gas	0.036	≥5
other	0.052	≥5

BARCT = Best Available Retrofit Control Technology

Process Heaters

Summary

Process heaters are used to transfer heat to fluids other than water, and are used where temperatures higher than those obtainable with steam are necessary. Typical process heater applications are preheating feeds (e.g., to distillation towers) or for supplying the energy needed to make a reaction take place in the process heater tubes (e.g., naphtha cracking). Process heaters are widely used in petroleum refineries and the chemical industry.

Oil and gas are the most common process heater fuels. Uncontrolled NO_X emissions from process heaters vary depending on the fuel and on whether or not the combustion air is preheated. With natural gas fuel and ambient temperature combustion air, emissions will be as low as 0.1 lb/MMBtu. If the combustion air is preheated, residual-oil-burning process heaters will have uncontrolled emissions of over 0.5 lb/MMBtu.

Available control strategies include combustion modifications to prevent NO_X formation, including use of low excess air, flue gas recirculation and low NO_X and radiant burners, as well as post-combustion controls to destroy NO_X once it has been formed. Potential emissions reductions range from 5 percent for simple, inexpensive combustion controls, to over 90 percent for radiant burners and selective catalytic reduction. Cost effectiveness varies with fuel and heater size. In 200-MMBtu/hr process heaters, control costs typically range from \$500 to \$2500 per ton of NO_X removed, although these costs may be as high as \$6000/ton in some cases.

Description of Source

Process heaters are used to transfer heat generated by the combustion of fuels to fluid contained in tubes. This fluid may either be process fluid or a heat transfer fluid. Process heaters are useful where a temperature higher than that easily obtainable with steam is necessary. (Boilers are used in such lower temperature applications.)

Process heaters are widely used in petroleum refineries, where they are called refinery heaters. Applications include preheating crude oil and other feeds for distillation, hydrotreating, catalytic cracking, alkylation, reforming and coking. In some operations, such as thermal cracking, chemical reactions occur in the process heater tubes. Total annual process heater energy consumption in refineries is approximately 2.3 quadrillion

Btu, equivalent to a mean of 260,000 MMBtu/hr (on a three-shift, 365-day basis).

In the chemical industry, process heaters are used in the manufacture of a number of organic and inorganic chemicals. On a heat input basis, most of this process heater capacity (approximately 80 percent) is used in high-temperature applications, including thermal cracking of ethane and other feeds to form ethylene, and steam reforming of natural gas to produce feedstocks for ammonia and methanol synthesis. Total annual energy consumption by chemical industry process heaters is approximately 700 trillion Btu, equivalent to a mean of 80,000 MMBtu/hr.

Basic process heater designs (*Figure 1*) include a firebox with one or more burners to combust fuel, and tubes that contain the process or heat transfer fluid. Most heat transfer to the tubes is radiative, although some convective transfer occurs in a cooler region between the firebox and the stack. As is the case with boilers, adding a convective section increases total heat transferred to the tubes and decreases stack gas temperature, thus increasing overall thermal efficiency.

Over 75 percent of process heaters are natural draft; air is drawn to the burners by a pressure differential created by the heat of combustion. Another type of process heater, the mechanical draft heaters, uses one or more fans to supply combustion air to, and remove flue gases from, the heater. While natural draft heaters are simpler and less expensive to construct, they do not allow fine control of combustion air flow. Further, mechanical draft systems can use combustion air preheat, which increases energy efficiency and decreases fuel consumption. However, higher heater temperatures that result from the use of preheated combustion air lead to increased thermal NO_X formation in the heater. This accounts for higher NO_X emissions from mechanical draft heaters than from natural draft heaters.

Process heaters burn a variety of fuels, including natural gas, refinery and process gas and distillate and residual oil.

Emissions Per Unit Output

Estimates of uncontrolled NO_X emissions identified in *Table 1* are excerpted from EPA's process heater ACT document, and were developed in a 1979 study sponsored by the American Petroleum Institute. As noted above, mechanical draft heaters normally use combustion air preheat, resulting in higher (thermal and total) NO_X emissions.

Typical uncontrolled NO_X emissions for gas-fired process heaters are 0.1-0.3 lb/MMBtu. For distillate- and residual-oil-fired heaters, typical uncontrolled emissions are 0.2-0.4 and 0.4-0.6 lb/MMBtu, respectively.

STAPPA/ALAPCO
Recommendation

▶ Process heaters are currently meeting limits similar to those for mid-sized industrial boilers, including 0.10, 0.12 and 0.30 lb/MMBtu for gas-, distillate-oil- and residual-oil-fired units, respectively. Agencies seeking additional reductions could require limits similar to those set by several California local districts, including 0.036 lb/MMBtu for gas and 0.05 lb/MMBtu for other liquid fuels.

National Emissions Estimate

Table 2 details how the 169,000 tons of estimated annual process heater NO_X emissions are broken down by fuel use.

Geographic Distribution of Sources and Emissions

Because process heater emissions come primarily from the chemical, petroleum and oil and gas industries, the state-by-state breakdown of emissions from process heaters follows the trends illustrated in emissions estimates from petroleum refineries and organic chemical manufacturing plants. The highest NO_X emissions from process heaters are in Texas, followed by Louisiana and Illinois.

Available Control Strategies

Many of the strategies for controlling process heater NO_X emissions are similar to those for industrial boilers. Peculiarities of heater design, such as the need for highly uniform temperatures in thermal cracking units, may change the relative attractiveness of the control alternatives.

Low Excess Air, which minimizes the air level above what is needed for complete combustion, lowers peak flame temperature and produces less oxidizing conditions, thus limiting thermal and fuel NO_X formation. Many process heater operators already minimize excess air levels to increase heater efficiency and decrease fuel requirements.

Excess air levels may be reduced on all process heaters, but this approach is most effective on mechanical draft heaters. Better control of air flow and the higher pressure drop across the burners caused by higher air flow in mechanical draft heaters results in improved fuel-air mixing, allowing greater reductions in excess oxygen concentrations before flame stability is affected.

Lowering excess air levels normally requires minimal capital investment, although retrofit controls may be needed on some older heaters. Emissions reductions achievable using low excess air depend upon the initial excess air level, the fuel and other heater-specific factors, with a probable reduction range of 5-20 percent.

Very low excess air levels may result in flame instability, as well as formation of soot and increased emissions of CO and hydrocarbons. A reducing atmosphere in the heater also may result in corrosion.

Low NO_X Burners with various designs have been retrofitted on a number of process heaters in the U.S. In staged-air burners, portions of the combustion air are introduced in secondary and tertiary zones, with reducing conditions in the fuel-rich, primary combustion zone inhibiting formation of both fuel and thermal NO_X. Staged-fuel burners have a primary combustion zone that is at a lower temperature, thus limiting thermal NO_X formation only; these burners are, therefore, applicable primarily to gas-fired heaters. Ultra-low NO_X burners combine techniques, including staged-air combustion, internal flue gas recirculation and steam injection.

Low NO_X burner retrofits on process heaters require, at a minimum, replacement of the burners. If plug-in replacement burners are not available, modifications to the heater wall will be necessary. In some cases, air plenums, burner controls and other hardware must be replaced. Space limitations, both for hardware placement and worker access, can increase retrofit costs.

Sometimes, low NO_X burner characteristics may make their installation less practical. Staged-air burners, for example, produce larger flames and retrofitting these in some process heaters would result in flame impingement on heater parts. Further, these burners must be spaced far enough apart to avoid having flames combine to produce high-temperature zones in the heater. If the existing burners are spaced too closely, a low NO_X burner retrofit would require extensive modification of the heater, and thus significant expense. These concerns are not relevant to staged-fuel burners, which produce smaller, more well-defined flames. Finally, heaters with large numbers of low heat output burners would also be expensive or impossible to retrofit.

Emissions reductions achievable with low NO_X burners are on the order of 30-60 percent. Installation of these burners may result in increased emissions of CO and hydrocarbons, with corresponding decreases in heater efficiency.

Radiant Burners, which burn a premixed fuel-air mixture in a glowing ceramic fiber matrix, produce little thermal NO_X because they operate at relatively low temperatures, typically on the order of 1800°F. These burners are applicable only on heaters burning gaseous fuels. Their low temperature may prevent radiant burner use in some high-temperature applications, such as ethane cracking. Further, the pressure drop across radiant burners may preclude their application on natural draft boilers.

There is little experience with the retrofit of radiant burners on process heaters. However, a number of new heaters have been designed around these burners, and several industrial and commercial boilers have been retrofit with radiant burners. Based on this experience, retrofits should be relatively simple. Radiant burners are designed for plug-in use and typically fill the volume taken up by a conventional burner flame.

Achievable controlled emissions using radiant burners have been below 25 ppm (0.03 lb/MMBtu), corresponding to emissions reductions of about 90 percent and greater on mechanical draft, gas-fired heaters.

Ceramic radiant burners may be brittle, creating difficulties primarily in their installation. Further, lower temperatures and different temperature profiles than conventional burners may result in lower process heater efficiencies.

Flue Gas Recirculation (FGR), recycling 15-30 percent of the flue gas to the burners, dilutes the combustion gases and has the primary effect of reducing peak flame temperature. Because FGR limits thermal NO_X formation but has little effect on fuel NO_X, it is more effective on natural-gas-fired heaters than on oil-fired heaters.

FGR is not universally applicable. Only mechanical draft heaters with burners that can accommodate increased gas flows are amenable to this technique. However, conversion of natural draft heaters to mechanical draft operation as part of an FGR retrofit is possible. In any case, process needs must be compatible with the lower flame temperatures generated.

Required FGR retrofit components include ductwork, recirculation fans and controls to vary damper settings on variable-load heaters. Retrofit difficulty in crowded plants may be greater.

Achievable emissions reductions are a function of the amount of flue gas recirculated, and thus are limited by efficiency losses and flame instability at higher recirculation rates. Limited performance data and experience on industrial boilers suggest that reductions on the order of 50-60 percent may be expected on natural-gas-fired heaters, and somewhat less on oil-fired heaters.

Selective Catalytic Reduction (SCR), the catalyst-accelerated reduction of flue gas NO_X with ammonia, has been retrofitted on a number of process heaters in the U.S. Some of these units have been in operation for over ten years.

The applicability of SCR is limited to heaters that have both a flue gas temperature appropriate for the catalytic reduction reaction and space for a catalyst bed large enough to provide sufficient residence time for the reaction to occur. Several different available catalyst formulations make the temperature window fairly wide — from approximately 500°F to over 1000°F. Installation of SCR on natural draft heaters requires conversion to mechanical draft in order to overcome the pressure drop across the catalyst. Finally, sufficient space must be available for ammonia storage.

SCR retrofit components include the catalyst and reactor, associated ductwork, an ammonia storage and distribution system and a control system. If heavy oil is to be used as a fuel, soot blowers should be installed to prevent catalyst plugging.

Typical emissions reductions achieved on process heaters in the U.S. have been 80-90 percent, with ammonia slip levels often below 10 ppm. In some cases, SCR systems have been installed that give lower emissions reductions where permit limits are less restrictive; actual achievable reductions are determined only by economics.

As noted above, ammonia slip can be limited to relatively low levels. Formation of ammonium bisulfate still may occur when firing sulfur-containing fuels, however. Other factors mitigating against the use of SCR include a decrease in heater efficiency as a result of catalyst pressure drop and the hazards of ammonia storage and handling. Regarding the latter, aqueous ammonia may be used in place of the more hazardous anhydrous ammonia, although the latter may in fact already be on site at many chemical plants.

Selective Noncatalytic Reduction (SNCR), using either ammonia (Exxon Thermal $DeNO_X$) or urea (NO_XOUT^{TM}) as the reducing agent for NO_X, has been implemented on a number of refinery and other process heaters, with the first ammonia-based systems installed almost 20 years ago. In the absence of a catalyst, the NO_X-reducing reactions that occur with ammonia or urea require relatively long residence times at high temperatures. The application of SNCR will be limited to process heaters that provide this combination of conditions.

Retrofit of either SNCR process requires the installation of injection and reagent storage and control systems. (Skid-mounted control systems typically are available.) A preparatory flow and modeling study normally will be performed to determine optimum reagent injection points. In the case of process heaters with variable loads, multiple injection levels and a more sophisticated control system may be required.

Demonstrated emissions reductions using both ammonia and urea have been on the order of 30-60 percent. Given higher reagent injection rates, ammonia slip will be greater than that found with SCR. As a result, substantial formation of ammonium bisulfate may occur when sulfur-bearing fuels are used. This ammonium bisulfate may collect not only in air preheaters, but also on cooler tubes in the convection section of the heater, requiring heater shutdowns so that the tubes can be washed with water.

Potential National Emissions Reduction

Potential reductions in process heater NO_X emissions are summarized in *Table 3*. Through implementation of a combination of combustion and post-combustion control strategies, a 50-percent overall reduction in national process heater emissions should be possible.

Costs and Cost Effectiveness

Capital and annual cost and cost effectiveness estimates for NO_X controls for model process heaters are given in *Tables 4, 5 and 6*. For larger (200-MMBtu/hr) heaters, capital costs range from $1600-$2600/MMBtu/hr of heat input for combustion modifications, such as flue gas recirculation and low-NO_X burners, to approximately $6500/MMBtu/hr for radiant burners and SCR. (Given economies of scale, these unit costs are approximately half those for 25-MMBtu/hr heaters) Similarly, total annual costs, including operation, maintenance and capital recovery range from below $500 per year per MMBtu/hr of heat input for LNB and FGR, to about $1000/year/MMBtu/hr for SNCR, to about $2000/year/MMBtu/hr for SCR and radiant burners.

Removal cost effectiveness varies with the fuel used and the extent of combustion air preheat, with "dirtier" sources having the lowest cost per ton of NO_X removed. For large mechanical draft, residual-oil-fired heaters, combustion modifications (LNB, FGR) cost $300-$600/ton NO_X removed, while post-combustion controls cost $900-$1500/ton. Corresponding numbers on mechanical draft, distillate-oil- and natural-gas-fired heaters are $600-$1100/ton (FGR, LNB) and $1700-$3500/ton (SCR, SNCR), with radiant burners (gas only) controlling NO_X for $2200-$2400/ton.

In general, regardless of the control technology chosen, removal costs for larger mechanical draft heaters will be below about $1500/ton if residual oil is burned, and $3000/ton if distillate oil or natural gas is burned. Costs for smaller heaters and natural draft heaters of all sizes will be somewhat higher.

Federal Rulemaking and/or Guidance Documents

EPA released an ACT covering NO_X emissions from process heaters in February 1993. This document was revised in September 1993.

For further information on the ACT, contact Bill Neuffer, U.S. Environmental Protection Agency, Emission Standards Division (MD-13), Research Triangle Park, NC 27711 (telephone: 919/541-5435).

State and Local Control Efforts

As indicated in *Table 7*, several states have promulgated rules limiting NO_X emissions from existing process heaters. Typical limits for process heaters burning natural gas are 0.1-0.2 lb/MMBtu. For those heaters burning oil, the median emission limit is 0.3 lb/MMBtu.

Retrofit limits in California are much more stringent, representing "best" rather than "reasonably available" control technology. Thus, as indicated in *Table 8*, typical limits in California are 0.036 lb/MMBtu for gas heaters and 0.052 lb/MMBtu for oil-burning heaters.

References

1. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. February 1993. *Alternative Control Techniques Document — NO_X Emissions from Process Heaters.*

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4. Environex, Inc. 1991. *Catalytic Emission Controls: Markets, Technology, Process Economics.*

5. California Air Resources Board, Stationary Source Division, and South Coast Air Quality Management District, Rule Development Division. April 29, 1987. *Technical Support Document for the Control of Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators and Process Heaters.*

6. U.S. Environmental Protection Agency. July 1993. *AIRS Facility Subsystem.*

7. Santa Barbara County Air Pollution Control District. December 1991. *Santa Barbara County 1991 Air Quality Attainment Plan. Appendix C: Emission Controls.*

Figure 1

Basic Process Heater Design

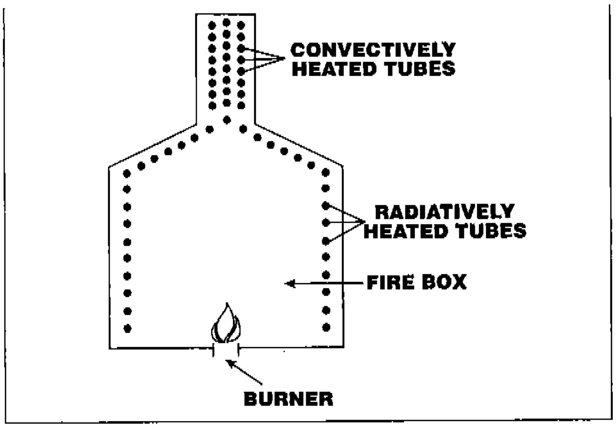

Table 1

Uncontrolled NO_X Emissions from Process Heaters

Fuel	Uncontrolled Emissions (lb/MMBtu) Natural Draft	Mechanical Draft
Residual Oil	0.42	0.54
Distillate Oil	0.20	0.32
Natural Gas	0.14	0.26

Source: EPA, February 1993.

Table 2

Estimated NO_X Emissions from Process Heaters

Fuel	Number of Process Heaters	National Emissions (tons/year)
Oil	390	18,000
Gas	4,270	152,000
Total	4,660	170,000

Source: EPA, AIRS Facility Subsystem, July 1993.

Table 3

Potential Emissions Reductions, Oil- and Gas-Fired Process Heaters

Control	NO_x Reduction Potential (%)		
	Residual Oil	Distillate Oil	Natural Gas
Low Excess Air	5-20	5-20	5-20
Flue Gas Recirculation	30-50	30-50	50-60
Low NOx Burner	30-60	30-60	30-60
Radiant Burner	N/A	N/A	90+
Selective Catalytic Reduction	75-90	80-90	80-90
Selective Noncatalytic Reduction	30-60	30-60	20-50

Source: EPA, February 1993.

Table 4

Costs of NO_x Control Technologies for Natural Gas-Fired Process Heaters[1]

Technology	Unit Size	Natural Draft Total Capital Cost ($)	Natural Draft Annual Cost ($/year)	Natural Draft Cost Effectiveness ($/ton)	Mechanical Draft Total Capital Cost ($)	Mechanical Draft Annual Cost ($/year)	Mechanical Draft Cost Effectiveness ($/ton)
LNB[2]	25 MMBtu/hr	82,000	14,000	2050-2560	120,000	21,000	1650-2070
	75 MMBtu/hr	210,000	36,000	1720-2160	310,000	54,000	1390-1740
	200 MMBtu/hr	350,000	61,000	1100-1370	530,000	91,000	890-1110
RB[3]	25 MMBtu/hr		See note 4 below		180,000	57,000	2340-2610
	75 MMBtu/hr		See note 4 below		500,000	160,000	2210-2470
	200 MMBtu/hr		See note 4 below		1,300,000	420,000	2170-2420
FGR[2]	25 MMBtu/hr		See note 4 below		91,000	20,000	1300-1550
	75 MMBtu/hr		See note 4 below		180,000	40,000	870-1050
	200 MMBtu/hr		See note 4 below		320,000	77,000	630-750
SNCR[2]	25 MMBtu/hr	230,000	45,000	8190-10,920	230,000	47,000	4620-6170
	75 MMBtu/hr	440,000	97,000	5870-7820	440,000	100,000	3370-4500
	200 MMBtu/hr	790,000	200,000	4500-6000	790,000	220,000	2640-3510
SCR[5]	25 MMBtu/hr		See note 4 below		380,000	77,000	3300-3800
	75 MMBtu/hr		See note 4 below		740,000	170,000	2600-3500
	200 MMBtu/hr		See note 4 below		1,330,000	340,000	2000-2700

[1]*Costs are estimated for process heaters with a capacity factor of 0.9 and are in 1993 dollars.*
[2]*Source: EPA, February 1993.*
[3]*Source: Santa Barbara County APCD, 1991.*
[4]*Requires conversion of heater to mechanical draft for application.*
[5]*Source: Environex, 1991.*

Table 5

Costs of NO_x Control Technologies for Distillate Oil-Fired Process Heaters[1]

		Natural Draft			Mechanical Draft		
Technology	Unit Size	Total Capital Cost ($)	Annual Cost ($/year)	Cost Effectiveness ($/ton)	Total Capital Cost ($)	Annual Cost ($/year)	Cost Effectiveness ($/ton)
LNB[2]	25 MMBtu/hr	82,000	14,000	1430-1790	120,000	21,000	1340-1680
	75 MMBtu/hr	210,000	36,000	1200-1510	310,000	54,000	1130-1410
	200 MMBtu/hr	350,000	61,000	770-960	530,000	91,000	720-900
FGR[2]	25 MMBtu/hr		See note 3 below		91,000	20,000	1580-2100
	75 MMBtu/hr		See note 3 below		180,000	40,000	1070-1420
	200 MMBtu/hr		See note 3 below		320,000	77,000	770-1020
SNCR[2]	25 MMBtu/hr	230,000	48,000	4880-6100	230,000	50,000	3190-3980
	75 MMBtu/hr	440,000	110,000	3580-4470	440,000	110,000	2370-2970
	200 MMBtu/hr	790,000	220,000	2810-3510	790,000	240,000	1900-2370
SCR[4]	25 MMBtu/hr		See note 3 below		380,000	83,000	2920-3280
	75 MMBtu/hr		See note 3 below		740,000	180,000	2160-2430
	200 MMBtu/hr		See note 3 below		1,330,000	390,000	1710-1930

[1]Costs are estimated for process heaters with a capacity factor of 0.9 and are in 1993 dollars.
[2]Source: EPA, February 1993.
[3]Requires conversion of heater to mechanical draft for application.
[4]Source: Environex, 1991.

Table 6

Costs of NO_x Control Technologies for Residual Oil-Fired Process Heaters[1]

		Natural Draft			Mechanical Draft		
Technology	Unit Size	Total Capital Cost ($)	Annual Cost ($/year)	Cost Effectiveness ($/ton)	Total Capital Cost ($)	Annual Cost ($/year)	Cost Effectiveness ($/ton)
LNB[2]	25 MMBtu/hr	82,000	14,000	680-850	120,000	21,000	800-1000
	75 MMBtu/hr	210,000	36,000	580-720	310,000	54,000	670-840
	200 MMBtu/hr	350,000	61,000	370-460	350,000	61,000	290-360
FGR[2]	25 MMBtu/hr		See note 3 below		91,000	20,000	930-1250
	75 MMBtu/hr		See note 3 below		180,000	40,000	630-840
	200 MMBtu/hr		See note 3 below		320,000	77,000	450-600
SNCR[2]	25 MMBtu/hr	230,000	50,000	2410-3010	230,000	52,000	1950-2440
	75 MMBtu/hr	440,000	110,000	1790-2230	440,000	120,000	1470-1840
	200 MMBtu/hr	790,000	240,000	1420-1780	790,000	250,000	1190-1490
SCR[4]	25 MMBtu/hr		See note 3 below		380,000	78,000	1630-1830
	75 MMBtu/hr		See note 3 below		740,000	170,000	1180-1330
	200 MMBtu/hr		See note 3 below		1,330,000	350,000	910-1030

[1]Costs are estimated for process heaters with a capacity factor of 0.9 and are in 1993 dollars
[2]Source: EPA, February 1993.
[3]Requires conversion of heater to mechanical draft for application.
[4]Source: Environex, 1991.

Table 7

Selected Process Heater Retrofit NO_x Emission Limits

State	Emission Limit (lb/MMBtu)[1] Gas-Fired	Distillate Oil-Fired	Residual Oil-Fired
Illinois	0.10-0.18	0.10-0.12	0.23-0.30
Louisiana	0.10-0.18	0.30	0.30
Michigan	0.20	0.30	0.40
Texas	0.10-0.18	0.30	0.30
Virginia	0.20	0.25	0.25

[1]Limits often vary with the extent of combustion air preheat.

Table 8

Process Heater Retrofit NO_x Limits in California

Fuel	Emission Limit (lb/MMBtu)	Boiler Size (MMBtu/hr)
Bay Area		
gas	0.036	≥10
other	0.052	≥10
San Joaquin		
gas	0.036	≥10
liquid	0.052	≥10
South Coast		
gas	0.037	≥2, <5
liquid	0.050	≥5
other	0.037	≥40
Ventura		
unspecified	0.050	≥5
California Air Resources Board: RACT Guidance		
gas	0.084	≥5
other	0.150	≥5
California Air Resources Board: BARCT Guidance		
gas	0.036	≥5
other	0.052	≥5

BARCT = Best Available Retrofit Control Technology

Gas Turbines

Summary

Gas turbines burn fuel, typically natural gas or distillate oil, to produce rotary motion. Turbines are related to, and in some cases derived from, jet engines. Simple cycle turbines have efficiencies of approximately 30 percent. Cogeneration cycle turbines, which use waste heat in the turbine exhaust gas to create steam, have higher efficiencies.

Gas turbines are used throughout the U.S. Common applications include driving gas and oil pipeline transmission equipment, the generation of electric power for both standby and continuous needs and the cogeneration of electricity and process steam for industrial use.

Typical uncontrolled NO_X emissions from turbines are 0.4-1.7 lb/MMBtu (99-430 ppm at 15 percent O_2) for turbines burning gas and 0.55-2.5 lb/MMBtu (150-680 ppm) for those burning distillate oil. Total national turbine emissions are 165,000 tons/year.

Three NO_X control strategies are in wide use on combustion turbines. Water injection and low NO_X combustors prevent the formation of NO_X, while selective catalytic reduction destroys NO_X once it is formed. All three strategies are capable of 90-percent emissions reductions, with cost effectiveness values below $1000/ton (see *Tables 4 and 5*).

Description of Source

Gas turbines use the combustion of fuel to create rotary motion. The gas turbine is one of two major types of internal combustion engines, the other being the reciprocating engine. Turbine outputs range from approximately 0.5 MW to over 200 MW.

Gas turbines are used to drive compressors and pumps in various industries. They are important in the oil and gas industry as power sources for extraction equipment, and also in pipeline transmission applications. Turbines are used to generate electric power for standby/emergency use and for continuous needs. In some cases, turbines are used to cogenerate steam and electricity, the latter for captive use or sale. Electric utilities are large users of turbines, for both peaking and baseload operations.

As illustrated in *Figure 1*, gas turbines have three principal components—the compressor, the combustor and the turbine. The compressor draws in and pressurizes ambient air. The combustor then burns fuel with a portion of the compressed air. The resulting combustion gases are diluted with the remainder of the air from the compressor to create a large volume of hot air. Finally, the hot, compressed gases expand in the turbine section, driving the turbine. The rotating turbine shaft is connected to a load to do work. However, approximately two-thirds of the energy generated is needed to drive the compressor, so that the overall gas turbine efficiency is one-third.

This description applies to simple cycle turbine operation. Simple cycle turbines are the least expensive to install, but have the highest fuel cost per unit of output, given that only 25-32 percent of the heat input is converted to shaft output. Simple cycle turbines are used in electric generation peaking and industrial applications. (If the hot gases leaving the turbine are used to heat the incoming gases in a heat exchanger, the arrangement is referred to as regenerative cycle, and has a somewhat higher efficiency.)

A cogeneration cycle gas turbine, illustrated in *Figure* 2, uses excess heat leaving the turbine to generate steam in a heat recovery steam generator (HRSG). Overall efficiencies of 75 percent are possible with cogeneration cycle turbines, at additional capital costs relative to simple cycle turbines. In some industrial applications, cogeneration turbines are used to generate process steam and electricity.

A combined cycle turbine is a cogeneration cycle turbine, but with steam generated in the HRSG used to run a steam turbine. This term normally is applied to turbines used in electricity generation, where both the gas and steam turbines drive generators. Combined cycle electric generating efficiencies approach 50 percent.

In some combined cycle/cogeneration applications, a burner fired with supplemental fuel may be installed in the duct leading to the HRSG (a "duct burner") to provide additional heat.

Gas turbines burn a variety of fuels, including natural gas, refinery gas and distillate oil. Lower-grade fuels are used in some cases, but tend to adversely affect the turbine blades, severely lowering cycle efficiencies.

Emissions Per Unit Output

The uncontrolled emissions identified in *Table 1* are taken from EPA's ACT document, and are based on data supplied by gas turbine manufacturers. These emissions are very dependent on turbine model and do not correlate with turbine size. All figures are by dry volume and are corrected to 15 percent oxygen.

Most natural-gas-fired turbines have uncontrolled NO_X emissions of 0.4-0.8 lb/MMBtu (100-200 ppm), although some models have emissions of up to 1.5-1.7 lb/MMBtu. Emissions from distillate-oil-fired turbines normally are 0.6-1.3 lb/MMBtu (150-350 ppm), with some turbines emitting up to 2.5 lb/MMBtu.

Where duct burners are used, they will cause additional uncontrolled emissions of 0.1 lb/MMBtu, or approximately 10 ppm if natural gas is used.

STAPPA/ALAPCO
Recommendation

▶ Agencies should consider regulating gas turbines burning natural gas at levels of 25-42 parts per million (ppm), and even as low as 9-15 ppm, since these latter limits are being achieved in California. Turbines burning distillate oil are being permitted at levels of 65 ppm and below, with some achieving levels of 25-42 ppm.

National Emissions Estimate

According to EPA's AIRS Facility Subsystem, approximately 1900 gas turbines emit an estimated 166,000 tons of NO_X per year. *Table 2* details the estimated breakdown of total gas turbines and emissions by fuel type.

Geographic Distribution of Sources and Emissions

Gas turbines are located at facilities throughout the U.S.

Available Control Strategies

Water/Steam Injection lowers peak flame temperatures by providing an inert diluent, thus limiting thermal NO_X formation. Water may be injected directly into the turbine combustor, or may be converted to steam using turbine exhaust waste heat (with an HRSG), and then injected into the combustor.

More steam than water must be used to achieve a comparable NO_X reduction. However, the use of steam results in a lower energy penalty the than use of water and may even provide NO_X reductions with no energy penalty if the waste heat used to generate steam would otherwise not be recovered.

Wet injection is applicable to most, if not all, gas turbines, and has been applied to a large number of turbines in the U.S. Required equipment, in addition to water/steam injection nozzles, includes a water treatment system, pumps or a steam generator, metering valves and controls and piping. (Untreated water will lead to deposits on turbine blades, lowering efficiency and perhaps damaging the turbine.) Most turbine manufacturers sell water and steam injection systems.

Controlled NO_x emissions are a function of the amount of water injected and of the fuel/nitrogen content as wet injection limits only thermal NO_x formation. For natural gas, controlled emissions levels of 25-75 ppm are attained with water-to-fuel ratios of about 0.5-1.5 lb/lb. (Approximately 1-2 lb steam/lb fuel is needed for equivalent control, given the lower heat capacity of steam relative to that of water.) For distillate oil, controlled emissions of 42-110 ppm are attained with similar water-to-fuel ratios. These controlled emissions levels correspond to 60-90 percent emissions reductions.

The need to increase water-to-fuel ratios for increased emissions reductions limits NO_x control capabilities. High water-to-fuel ratios result in increased hydrocarbon and greatly increased CO emissions. Further, because heating injected water consumes energy, turbine fuel efficiency may decrease. Wet injection may increase required turbine maintenance as a result of pressure oscillations or erosion caused by contaminants in the feed water.

Finally, the water treatment plant creates wastewater. This wastewater is enriched approximately threefold by the dissolved minerals and pollutants that were in the raw water.

Dry Low NO_x Combustors encompass several different technologies. Lean premixed combustion is the commercially available technology that affords the largest NO_x reductions. It functions by providing a large amount of excess air to the combustion chamber, lowering peak flame temperatures by dilution. Air and fuel are premixed in lean premixed combustors to avoid the creation of local fuel-rich, and therefore high-temperature, regions.

While retrofit low NO_x combustors are not available for all turbine models, they have been installed on many turbines in the U.S. Rapid technical development suggests that there will be greater availability within the next few years. Because lean premixed combustors reduce thermal NO_x generation only, they are less effective on oil-fired than on gas-fired turbines. In fact, water/steam injection provides comparable reductions on oil-fired turbines without retrofit of low NO_x combustors.

Lean premixed combustor retrofits face varying difficulties. Except in the case of silo combustors, which are external to the turbine body, the retrofits may require some modification of the combustor section of the turbine.

Controlled emissions levels achievable on gas-fired turbines are on the order of 25-42 ppm. On some larger turbines, manufacturers are guaranteeing emissions of 9 ppm, and more will approach this limit with improvements in technology. These figures correspond to NO_x emissions reductions of 60-95 percent.

The need for a pilot flame, which burns hot and thus produces relatively large NO_x emissions, limits achievable reductions. Further, maximum reductions are attainable only at high turbine loads. Given reduced fuel requirements at low loads, premixing would yield air-fuel mixtures near the lean flammability limit, with resulting flame instability and high CO emissions. Thus, lean premixed combustors use diffusion flames at low loads.

Low NO_x combustors tend to produce somewhat elevated CO levels, particularly at low and intermediate loads.

Selective Catalytic Reduction (SCR) is the only technology that will control duct-burner NO_x emissions.

SCR has been installed on a number of gas turbines in the U.S. On most cogeneration and combined cycle turbines, the catalyst has been installed in a lower temperature region downstream from the superheater in the HRSG. Space limitations may preclude this placement at some sites. In at least one case, a catalyst effective at higher temperatures, and based on a zeolite formulation, has been installed upstream of the HRSG. While there has been less experience with simple cycle turbines that have exhaust temperatures above the operating limit for base metal catalysts, the zeolite catalyst should also be useful in these applications.

Required elements of SCR retrofits include a catalyst, an ammonia storage and distribution system and controls. The difficulty of the SCR retrofit will depend on space constraints.

Achievable emissions reductions using SCR exceed 90 percent, which corresponds to controlled emissions below 10 ppm and 25 ppm for many gas- and oil-fired turbines. SCR often has been installed in combination with other technologies, such as wet injection, which affords control to very low emission levels.

Ammonia slip will occur with SCR use. At many installations, ammonia slip may be limited to 2 ppm or below. Even this amount, however, corresponds to several tons of ammonia per year at larger turbines. Further, ammonium bisulfate formation and deposition in the HRSG will accompany ammonia slip when sulfur-bearing fuels are burned. The typical use of natural gas and other low-sulfur fuels, along with low ammonia slip, should limit this as a concern.

Other issues regarding SCR use include an efficiency loss due to the pressure drop across the catalyst and catalyst poisoning. Regarding the latter, experience in the U.S. and abroad suggests that catalyst life in gas turbine applications should be long, normally over five years. Catalyst poisoning typically is not a problem, given the clean fuels burned.

At least one manufacturer provides a precious metal oxidation catalyst that has been formulated to provide dual NO_x reduction/CO oxidation capabilities.

Potential National Emissions Reduction

Potential reductions in gas turbine emissions are summarized in *Table 3*. All control strategies afford emissions reductions of at least 60 percent, and all will provide reductions of 90 percent under some circumstances.

Costs and Cost Effectiveness

Capital and annual costs and cost effectiveness values are provided in *Tables 4 and 5*. Total capital costs for individual technologies on 100-MW turbines are on the order of \$25-\$30/kW for water injection and low NO_x combustion, \$35/kW for selective catalytic reduction, and \$40/kW for steam injection. (Capital costs for small turbines are perhaps four- to five-fold more expensive per unit of output.) For low NO_x combustors, annual costs are limited to capital recovery, and therefore will be on the order of \$3/year/kW on large turbines. Steam and water injection will have total annual costs of \$12-\$17/year/kW, and SCR, \$22-\$25/year/kW.

Cost effectiveness numbers for 100 MW continuous-duty turbines are low — about \$150-\$200 per ton of NO_x removed for combustor retrofits, \$400-\$700/ton for wet injection and \$600-\$1000/ton for SCR. On 5-MW continuous duty turbines, costs rise to a minimum of about \$2500/ton, but may be higher on peaking turbines.

Federal Rulemaking and/or Guidance Documents

EPA released an ACT addressing NO_x emissions from stationary gas turbines in January 1993.

For further information on the ACT, contact Bill Neuffer, U.S. Environmental Protection Agency, Emission Standards Division (MD-13), Research Triangle Park, NC 27711 (telephone: 919/541-5435).

State and Local Control Efforts

Gas turbine NO_x RACT limits recommended by NESCAUM and those promulgated by the states are identified in *Table 6*. The median RACT limit on gas-fired turbines is 42 ppm, with a range of 25-75 ppm. On oil-fired turbines, limits range from 60-110 ppm, with a median value of 75 ppm. As illustrated in *Table 7*, most limits in California are similar, although the South Coast and Bay Area Air Quality Management Districts limit emissions on turbines with outputs as low as 10 MW to 9-15 ppm.

References

1. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. January 1993. *Alternative Control Techniques Document — NO_x Emissions from Stationary Gas Turbines.*

2. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. February 1992. *Summary of NO_x Control Techniques and Their Availability and Extent of Application.*

3. Radian Corporation. July 1991. *Sourcebook: NO_x Control Technology Data.* Prepared for U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory.

4. Environex, Inc. 1991. *Catalytic Emission Controls: Markets, Technology, Process Economics.*

5. California Air Resources Board, Stationary Source Division, and South Coast Air Quality Management District, Rule Development Division. April 29, 1987. *Technical Support Document for the Control of Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators and Process Heaters.*

6. California Air Resources Board, Stationary Source Division. May 18, 1992. *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for the Control of Oxides of Nitrogen from Stationary Gas Turbines.*

7. The Babcock & Wilcox Company.1992. *Steam: Its Generation and Use.* 40th Edition.

8. U.S. Environmental Protection Agency. July 1993. *AIRS Facility Subsystem.*

Figure 1

Basic Gas Turbine Components

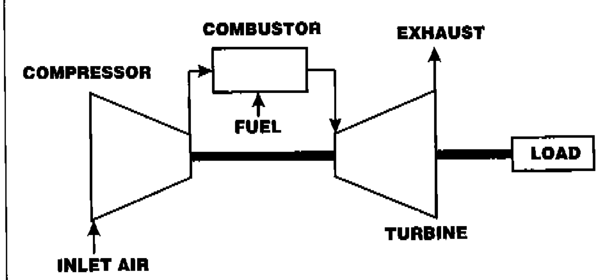

Figure 2

Gas Turbine Configurations for Different Operation Cycles

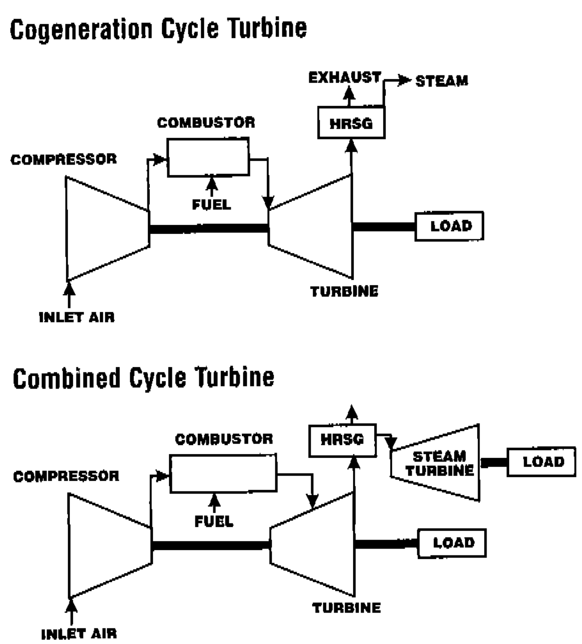

Table 1

Uncontrolled NO_x Emissions from Combustion Turbines

	Uncontrolled NO_x Emissions	
Fuel	ppmv	lb/MMBtu
Natural Gas	99-430	0.40-1.7
Distillate Oil	150-680	0.55-2.5

Source: EPA, January 1993.

Table 2

Estimated NO_x Emissions from Gas Turbines

Fuel	Number of Gas Turbines	National Emissions (tons/year)
Oil	559	11,600
Gas	1284	152,200
Other	36	900
Total	1879	164,700

Source: EPA, AIRS Executive.

Table 3

Potential Emissions Reductions from Gas Turbines

Control	Emissions Reduction (%)
Water/Steam Injection	70-90
Low NO_x Combustors	60-90
SCR	90

Source: EPA, January 1993.

Table 4

Costs of NO_x Control Technologies for Gas Turbines[1]

Technology	Unit Size (MW) and Operation	Gas-Fired Total Capital Cost ($)	Gas-Fired Annual Cost ($/year)	Gas-Fired Cost Effectiveness ($/ton)	Oil-Fired Total Capital Cost ($)	Oil-Fired Annual Cost ($/year)	Oil-Fired Cost Effectiveness ($/ton)
Water Injection[2]	5, continuous[3]	544,000	165,000	1390-1780	570,000	195,000	1000-1300
	25, continuous	1,140,000	408,000	690-880	1,210,000	547,000	560-710
	100, continuous	2,560,000	1,180,000	500-640	2,800,000	1,720,000	440-560
	25, peaking[4]	1,140,000	248,000	1670-2150	1,210,000	292,000	1190-1520
	100, peaking	2,560,000	624,000	1050-1350	2,800,000	786,000	800-1020
Steam Injection[2]	5, continuous	710,000	185,000	1560-2000	745,000	200,000	1010-1300
	25, continuous	1,610,000	448,000	760-970	1,730,000	514,000	520-670
	100, continuous	3,900,000	1,250,000	520-670	4,230,000	1,490,000	380-480
	25, peaking	1,610,000	319,000	2150-2760	1,730,000	350,000	1520-1820
	100, peaking	3,900,000	813,000	1370-1760	4,231,000	917,000	930-1190
Low NO_x Combustor[2]	5, continuous	482,000	63,400	530-800		See note 5 below	
	25, continuous	1,100,000	145,000	240-370		See note 5 below	
	100, continuous	2,400,000	316,000	130-200		See note 5 below	
	25, peaking	1,100,000	258,000	980-1470		See note 5 below	
	100, peaking	2,400,000	316,000	530-800		See note 5 below	
SCR[6]	5, continuous	572,000	258,000	2180-2450	572,000	274,000	1390-1560
	25, continuous	1,540,000	732,000	1230-1390	1,544,000	812,000	820-920
	100, continuous	3,300,000	2,190,000	920-1030	3,302,000	2,500,000	630-710
	25, peaking	1,540,000	517,000	3480-3920	1,540,000	537,000	2170-2440
	100, peaking	3,300,000	1,430,000	2400-2700	3,300,000	1,510,000	1530-1720

[1] *Costs in 1993 dollars.*
[2] *Source: EPA, January 1993.*
[3] *Continuous turbines operate 8000 hours per year.*
[4] *Peaking turbines operate 2000 hours per year.*
[5] *Not applicable.*
[6] *Costs derived from Environex, 1991 and EPA, January 1993.*

Table 5

Costs of NO_x Control Technologies for Gas Turbines Per Unit of Output[1]

Technology	Unit Size (MW) and Operation	Gas-Fired Total Capital Cost ($/kW)	Gas-Fired Annual Cost ($/year/kW)	Gas-Fired Cost Effectiveness ($/ton)	Oil-Fired Total Capital Cost ($/kW)	Oil-Fired Annual Cost ($/year/kW)	Oil-Fired Cost Effectiveness ($/ton)
Water Injection[2]	5, continuous[3]	109.00	33.00	1390-1780	114.00	39.00	1000-1300
	25, continuous	46.00	16.00	690-880	48.00	22.00	560-710
	100, continuous	26.00	12.00	500-640	28.00	17.00	440-560
	25, peaking4	46.00	10.00	1670-2150	48.00	12.00	1190-1520
	100, peaking	26.00	6.00	1050-1350	28.00	8.00	800-1020
Steam Injection[2]	5, continuous	142.00	37.00	1560-2000	149.00	40.00	1010-1300
	25, continuous	64.00	18.00	760-970	69.00	21.00	520-670
	100, continuous	39.00	13.00	520-670	42.00	15.00	380-480
	25, peaking	64.00	13.00	2150-2760	69.00	14.00	1520-1820
	100, peaking	39.00	8.00	1370-1760	42.00	9.00	930-1190
Low NO_x Combustor[2]	5, continuous	96.00	13.00	530-800		See note 5 below	
	25, continuous	44.00	6.00	240-370		See note 5 below	
	100, continuous	24.00	3.00	130-200		See note 5 below	
	25, peaking	44.00	10.00	980-1470		See note 5 below	
	100, peaking	24.00	3.00	530-800		See note 5 below	
SCR[6]	5, continuous	114.00	52.00	2180-2450	114.00	55.00	1390-1560
	25, continuous	62.00	29.00	1230-1390	62.00	32.00	820-920
	100, continuous	33.00	22.00	920-1030	33.00	25.00	630-710
	25, peaking	62.00	21.00	3480-3920	62.00	21.00	2170-2440
	100, peaking	33.00	14.00	2400-2700	33.00	15.00	1530-1720

[1] *Costs in 1993 dollars.*
[2] *Source: EPA, January 1993.*
[3] *Continuous turbines operate 8000 hours per year.*
[4] *Peaking turbines operate 2000 hours per year.*
[5] *Not applicable.*
[6] *Costs derived from Environex, 1991 and EPA, January 1993.*

Table 6

Selected Combustion Turbine NO_x Limits (15% O_2)[1]

Jurisdiction/Fuel Type	Emission Limits (ppm) Simple Cycle	Combined Cycle	Regenerative
NESCAUM[2]			
gas	55	42	
oil	75	65	
Connecticut[3]			
gas	55	55	
oil	75	75	
Delaware			
gas	42	42	
liquid	88	88	
Illinois			
gas	25-42	25-42	
oil	60-65	60-65	
Michigan			
	75	75	
Louisiana			
gas	65	65	
liquid	75	75	
New Jersey			
gas	51	38	
oil	97	85	
New York			
gas	50	42	50
multiple fuels	100		100
oil		65	
Ohio			
gas	75	75	75
oil	110	110	110
Texas			
gas	42	42	
oil	65	65	
Virginia[4]			
gas	42	42	
oil	65/77	65/77	

[1] In most cases, the jurisdictions specify a threshold size cutoff. These thresholds vary from turbines rated at 10 MMBtu/hr or greater (NY) to 20 MMBtu/hr (OH) to 25 MMBtu/hr (NESCAUM) to 30 MMBtu/hr (NJ) to 100 MMBtu/hr or greater (CT and VA).
[2] The NESCAUM limits are recommendations.
[3] The Connecticut limits shown are for turbines ≥ 100 MMBtu/hr. For smaller turbines, the limits are 228 ppm (gas) and 219 ppm (oil).
[4] The Virginia limits for oil (77 ppm) are for fuel bound nitrogen ≥ .015%.

Table 7

Gas Turbine Retrofit NO_x Limits in California

Fuel	Emission Limits (ppm at 15% O_2)	Turbine Output (MW)
Bay Area		
unspecified	42	≥0.3, < 10
	9-15[1]	≥10
Great Basin Valley		
gas	42	≥110
liquid	75	≥110
San Bernadino		
gas	42	≥40.6
liquid	75	≥40.6
San Diego		
gas	42	≥3.7
liquid	75	≥3.7
South Coast		
unspecified	25	≥0.3, <2.9
	9-15[1]	≥2.9, <10
	9-12[1]	≥10
California Air Resources Board: RACT Guidance		
gas	42	≥0.3
oil	65	≥0.3
California Air Resources Board: BARCT Guidance		
gas	42	≥0.3, <2.9
oil	65	≥0.3, <2.9
gas	25	≥2.9, <10
oil	65	≥2.9, <10
gas	9-15[1]	≥10
oil	25-42[1]	≥10

[1] Lower limit applies to turbines retrofitted with SCR.
BARCT = Best Available Retrofit Control Technology

Reciprocating Internal Combustion Engines

SUMMARY

Stationary reciprocating internal combustion engines are the stationary relatives of motor vehicle engines, using the combustion of fuel in cylinders to drive pistons, with crankshafts to convert the linear piston motion to rotary motion. Reciprocating engines are used throughout the U.S. to drive compressors, pumps, electric generators and other equipment. One prominent use of large engines is as gas pipeline compressor station prime movers.

Ignition of the fuel in reciprocating engines may be initiated by a spark or by the heat generated in the compression stroke of a piston. Spark ignition engines typically burn gasoline or, in large engines, natural gas, while compression ignition engines burn diesel oil or a dual-fuel (diesel oil-natural gas) mixture. For gas-fired spark ignition engines, uncontrolled NO_X emissions typically are 10-27 g/bhp-hr, with a mean near 16 g/bhp-hr. Compression ignition engine emissions are 5-20 g/bhp-hr, with a mean near 10 g/bhp-hr.

Available NO_X control strategies for reciprocating engines range from combustion modifications (including air-to-fuel ratio and ignition timing changes) to catalytic techniques for exhaust gas NO_X destruction. Potential NO_X reductions are as low as 5 percent for changes in engine tuning, to as high as about 98 percent for the installation of a three-way or non-selective catalytic reduction (NSCR) catalyst. Control costs vary with the extent of reduction, the fuel and the engine type, but in many cases are below about \$1000/ton of NO_X for larger engines, even for 90-percent emissions reductions (see *Tables 4 and 5*).

DESCRIPTION OF SOURCE

Stationary reciprocating internal combustion engines are the stationary relatives of motor vehicle engines and include spark ignition, compression ignition, rich-burn and lean-burn engine types. In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft.

Several million stationary reciprocating engines are in use throughout the U.S. In general industry, these engines provide shaft power to drive process equipment, compressors, pumps, standby generator sets and other machinery. Agricultural uses are similar, with many engines driving irrigation pumps. Reciprocating engines find wide application in municipal water supply and wastewater treatment and in commercial and institutional emergency power generation.

Reciprocating engines are used in the oil and gas industry for both production and transmission. Over 6000 large engines (350 hp or greater capacity) are estimated to be in use as gas pipeline compressor station prime movers.

There are two basic types of reciprocating engines — spark ignition and compression ignition. Spark ignition engines use a spark (across a spark plug) to ignite a compressed fuel-air mixture. Typical fuels for such engines are gasoline, natural gas and sewage and landfill gas. Compression ignition engines compress air to a high pressure, heating the air to the ignition temperature of the fuel, which then is injected. The high compression ratio used for compression ignition engines results in a higher efficiency than is possible with spark ignition engines. Diesel fuel oil is normally used in compression ignition engines, although some are dual-fueled (natural gas is compressed with the combustion air and diesel oil is injected at the top of the compression stroke to initiate combustion).

Reciprocating engines have either four-stroke or two-stroke operating cycles. Typical automotive engines use the familiar four-stroke cycle of intake, compression, power and exhaust. Two-stroke engines produce more power per unit of weight, and are common in gas transmission applications. In the compression stroke, air or an air-fuel mixture is blown into the cylinder (and waste gases out of the cylinder) by a low-pressure blower as the piston moves upward. Ignition of fuel forces the piston downward in the power stroke.

Air is drawn into reciprocating engines by downward motion of the pistons (natural aspiration), or is fed to the engine with a turbocharger (a compressor powered by an exhaust-driven turbine) or, in the case of two-stroke engines, by a low-pressure blower. Because a turbocharger produces a greater cylinder pressure, it increases engine power 1.5- to 3-fold over natural aspiration. Fuel either is mixed with air in a carburetor or is injected directly into the cylinders by fuel injection. Diesel and other compression ignition engines all use fuel injection.

A final classification of reciprocating engines that influences the choice of NO_x control alternatives is based on the engine air-to-fuel ratio and the exhaust oxygen content. Rich-burn engines, which include four-stroke spark ignition engines, typically operate with an air-to-fuel ratio near stoichiometric and exhaust oxygen concentrations of 1 percent or less. Lean-burn engines, which include two-stroke spark ignition and all compression ignition engines, have a lean (i.e., air-enriched) air-to-fuel ratio, and typical exhaust oxygen concentrations of greater than 1 percent. Note, however, that some engine manufacturers and state and local air pollution control agencies have alternative definitions of rich- and lean-burn.

STAPPA/ALAPCO
Recommendation

▶ State and local agencies seeking NO_x reductions from internal combustion engines can impose controls more stringent than RACT requirements currently being implemented in several states. Agencies should consider the limits set in several California local districts, including requirements for rich-burn gas-fired engines between 0.4-0.8 g/bhp-hr, for lean-burn engines as low as 0.5-0.6 g/bhp-hr and for diesel engines at levels between 0.5-1.1 g/bhp-hr.

Stationary reciprocating engines, as described above, range in output from 1 hp to 10,000 hp, which corresponds approximately to 0.75 kW to 7.5 MW. Very small engines, that are typically portable, are used to drive appliances, air compressors, etc. These normally are in the 2-16 hp range, have a 1-3" cylinder bore (diameter), a high crankshaft speed of 3000-4000 rpm and are gasoline-powered. Small-bore engines are somewhat larger — with 3-50 hp output and a 3-5" bore — run at 1000-4000 rpm on diesel oil or gasoline and often are used for remote electric power generation. Medium-bore engines also run at 1000-4000 rpm and are diesel- or gasoline-fueled; these engines have 3.5-9" cylinder diameters, are rated at 50-1200 hp and have many industrial and commercial applications. Finally, large-bore engines are used for oil and gas production and municipal electricity generation. These have outputs of 400-13,000 hp, an 8-18" bore, low crankshaft speeds of 250-1,200 rpm and burn natural gas or diesel oil or are dual-fueled.

Emissions Per Unit Output

The uncontrolled NO_x emissions from stationary reciprocating internal combustion engines identified in *Table 1* are taken from EPA's ACT and are derived from information provided by engine manufacturers. Gas-fired spark ignition engines have typical uncontrolled NO_x emissions of 10-27 g/bhp-hr, with a mean near 16 g/bhp-hr. Compression ignition engines have uncontrolled emissions in the 5-20 g/bhp-hr range, with a mean near 10 g/bhp-hr. These may be converted to ppm at 15 percent O_2 using an approximate conversion factor of 70 ppm per g/bhp-hr.

National Emissions Estimate

According to EPA, the approximately 9000 reciprocating engines in the U.S. emit an estimated 784,000 tons of NO_x per year. The majority of these engines run on natural gas. *Table 2* provides a breakdown of total engines and emissions by fuel type.

Geographic Distribution of Sources and Emissions

Reciprocating engines are used throughout the U.S.

Available Control Strategies

Several combustion modification strategies are available for controlling NO_x emissions from reciprocating engines. Air/fuel ratio adjustment, low emission combustion and pre-stratified charge all function by modifying the combustion zone air/fuel ratio, thus influencing oxygen availability and peak flame temperature. Ignition timing retard lowers the peak flame temperature by delaying the onset of combustion. Two post-combustion strategies, selective catalytic reduction and non-selective catalytic reduction, destroy NO_x once it has been formed. Finally, electrification prevents all direct NO_x emissions.

Several issues influence the choice of NO_x control strategies for different reciprocating engine applications. In industrial, commercial and municipal applications, the engine is a small part of the total plant and little trained manpower will be available for emissions control system operation and maintenance. The issue of manpower availability is magnified for gas pipeline compressor station and other remote applications, where no personnel will be present on a daily basis and automated engine operation is the rule, even when substantial load variations may occur.

Air/Fuel (A/F) Ratio Adjustment takes different directions in rich- and lean-burn spark ignition engines. Lowering the air-to-fuel ratio in rich-burn engines limits oxygen availability in the cylinder, thus decreasing NO_x emissions both by lowering peak flame temperature and by producing a reducing atmosphere. This technique is analogous to the use of low excess air in boilers and process heaters and, similarly, has the limitation of producing excess CO and hydrocarbon emissions at very low air-to-fuel ratios. It is generally applicable to rich-burn engines and, in addition to simple adjustment of the air-to-fuel ratio, requires the installation of a feedback controller so that changes in load and other operating conditions may be followed. Additional modification of turbocharged engines may be necessary.

A/F ratio adjustment is a well-demonstrated alternative in rich-burn engines and typically yields 10-40 percent reductions in NO_x emissions. This range is broad in part because a wide range of existing air/fuel ratios translates into variable scope for emissions reductions using this technique. Achievable reductions are limited by the levels of collateral CO and hydrocarbon emissions that are acceptable, with CO emissions increasing by over an order of magnitude in some cases, and to a lesser extent by reduced fuel efficiency. On the other hand, installation of a feedback controller improves engine responsiveness to changes in operating conditions and avoids lean misfire, among other benefits.

In lean-burn engines, increasing the air-to-fuel ratio decreases NO_x emissions. Extra air dilutes the combustion gases, thus lowering peak flame temperature and reducing thermal NO_x formation. In order to avoid an engine derate, air flow to the engine must be increased at constant fuel flow, with the result that installation of a turbocharger (or modification of an existing one) is necessary to implement this technique. An automatic A/F controller also will be required for variable load operation.

A/F ratio adjustment is generally applicable to lean-burn engines, although space constraints may limit the extent to which turbocharger capacity may be increased. This control method is most effective on fuel-injected engines, in that carbureted engines do not have the same A/F in each cylinder, thereby limiting changes in this ratio.

Reductions in lean-burn engine NO_x emissions of 5-30 percent are possible by modifying the air-to-fuel ratio. Achievable emissions reductions are limited by combustion instability and lean misfire that occur as the lean flammability limit is approached, and by decreased engine efficiency.

A/F ratio adjustment is not applicable to compression ignition engines.

Ignition Timing Retard lowers NO_x emissions by moving the ignition event to later in the power stroke, when the piston has begun to move downward. Because the combustion chamber volume is not at its minimum, the peak flame temperature will be reduced, thus reducing thermal NO_x formation.

Ignition timing retard is applicable to all engines. It is implemented in spark ignition engines by changing the timing of the spark, and in compression ignition engines by changing the timing of the fuel injection. While timing adjustments are straightforward, replacement of the ignition system with an electronic ignition control or injection timing system will provide better performance with varying engine load and conditions.

Emissions reductions attainable using ignition timing retard are variable, depending upon the engine design and operating conditions, and particularly on the air/fuel ratio. Reductions also are restricted by limitations on the extent to which ignition may be delayed, in that excess retard results in engine misfire. Retard also normally results in decreased fuel efficiency. For spark ignition engines, achievable emissions reductions vary from 0-40 percent, and for compression ignition engines, from 20-30 percent.

Ignition timing retard results in increased exhaust temperatures, which may result in reduced exhaust valve and turbocharger life. On diesel engines, it also may result in black smoke.

Prestratified Charge is a technology for injecting fuel and air into the intake manifold in distinct "slugs," which become separate fuel and air layers upon intake into the cylinders. This control alternative thus creates a fuel-rich, easily ignitable mixture around the spark plug and an overall fuel-lean mixture in the piston. Combustion occurs at a lower temperature, thereby producing much less thermal NO_X, but without misfire even as the low flammability limit is approached.

Prestratified charge is applicable to carbureted, spark ignition four-stroke engines. Engines which are fuel-injected or blower-scavenged cannot use this technique. Kits for retrofitting prestratified charge are available for most engines and require installation of new intake manifolds, air hoses and filters, control valves and a control system. Controlled emissions normally are less than 2 g/bhp-hr on natural-gas-fueled engines, corresponding to emissions reductions of 80-95 percent.

Limitations to the use of prestratified charge include increases in CO and hydrocarbon emissions, which are a consequence of low combustion temperatures. Reductions in rated power output of up to 20 percent on naturally aspirated engines and up to 5 percent on turbocharged engines also are observed.

Low Emission Combustion is the combustion of a very fuel-lean mixture. Under these conditions, NO_X emissions, as well as CO and hydrocarbons, are severely reduced.

Implementation of low emission combustion requires considerable engine modification. (This is referred to as a CleanBurn® retrofit by one manufacturer.) Rich-burn engines must be entirely rebuilt, with addition or replacement of the turbocharger and installation of new air intake and filtration, carburetor and exhaust systems. The difficulty of burning very lean mixtures results in the need to modify the combustion chamber, which implies replacing pistons, cylinder heads, the ignition system and the intake manifold. While small cylinder designs that promote air-fuel mixing are available, precombustion chambers must be installed on larger engines. These chambers have 5-10 percent of the cylinder volume and allow ignition of a fuel-rich mixture that ignites the lean mixture in the cylinder.

The applicability of low emission combustion is somewhat limited. Conversion kits are not available for all engines and refitted engines may have degraded load following capabilities. Achievable controlled emissions are 1-2 g/bhp-hr for rich-burn engines, which corresponds to an emissions reduction of 70-90 percent, and 1.5-3 g/bhp-hr for lean-burn spark ignition engines, or an emissions reduction of about 80-93 percent.

Low emission combustion is not effective for diesel engines, but does work for dual-fuel engines, allowing a reduction in the fraction of diesel oil pilot fuel to 1 percent of the total, and limiting emissions to 1-2 g/bhp-hr (i.e., a decrease in emissions of 60-80 percent). Some reductions in exhaust opacity have been claimed when low emission combustion is implemented on dual-fuel engines.

Non-Selective Catalytic Reduction (NSCR) uses the three-way catalysts familiar in automotive applications to promote the reduction of NO_X to nitrogen and water. Exhaust carbon monoxide and hydrocarbons are simultaneously oxidized to carbon dioxide and water in this process.

NSCR is applicable only to rich-burn engines with exhaust oxygen concentrations below about 1 percent. Lean-burn engine exhaust will contain insufficient CO and hydrocarbons for the reduction of the NO_X present. NSCR retrofits, in addition to the catalyst and catalyst housing, require installation of an oxygen sensor and feedback controller to maintain an appropriate air-to-fuel ratio under variable load conditions.

Controlled emissions achievable with NSCR are below 1 g/bhp-hr, corresponding to emissions reductions greater than 90 percent.

A primary concern regarding the use of NSCR is that catalyst deactivation may result in a need for frequent and expensive catalyst replacement, as well as operation out of compliance with emission limits. Lubricants and dirty fuels may contain compounds that reversibly or irreversibly poison the catalyst, or alternatively reduce catalyst activity by pore-blocking. Temperature excursions caused by back-firing may also lower catalyst activity. Current catalysts appear to be resistant to many common poisons. Further, several manufacturers offer cleaning services for reversibly deactivated catalysts and also will take back spent catalysts for recycling.

An additional concern regarding NSCR is that the pressure drop across the catalyst reduces engine efficiency, thus increasing fuel consumption for constant power output. According to one estimate, fuel consumption per unit output may increase by approximately 0.5 percent.

Selective Catalytic Reduction (SCR), the catalyzed reduction of NO_X with injected ammonia, has been implemented on a number of gas, diesel and dual-fuel engines in the U.S. and abroad. SCR is applicable only to lean-burn engines with greater than about 1 percent exhaust oxygen, as oxygen is a reagent in the selective reduction reaction.

Retrofitting SCR involves installation of the reactor and catalyst, appropriate ductwork, an ammonia storage and distribution system and a control system for variable load operation. Achievable emissions reductions are limited only by the amount of catalyst used, and typically are on the order of 90 percent, yielding controlled emissions below 2 g/bhp-hr.

Widespread application of SCR has been slowed by a number of issues. In addition to cost, these include ammonia slip, the possibility of catalyst poisoning, the need for operation in remote locations and the requirement for continuous emissions monitoring systems (CEMS), claimed to be expensive and temperamental, for controlling ammonia injection in variable load operation.

While ammonia slip cannot be avoided, it has been limited to below 10 ppm in most reciprocating engine applications. At these low slip levels, problems with ammonium bisulfate formation are avoided with most sulfur-bearing fuels. Where variable loads are encountered, feed-forward/feed-back controls have been used to minimize slip while maximizing NO_X conversion over the entire load range.

Research in the U.S. and Japan is aimed at the development of catalysts that would allow the use of natural gas rather than ammonia in SCR. Such catalysts would be useful in pipeline transmission and similar applications where a source of natural gas is readily available.

Given the prevalence of phosphorus-containing lubricating oils, catalyst poisoning remains a concern. If phosphorus-free oils are used, catalyst life may exceed five years, although typical guarantees are for two to three years. On the other hand, some engine manufacturers have expressed concerns that engine life may be reduced if low-phosphorus oils are used.

Several SCR systems have been installed in remote applications. Typically, operation of these is fully automated and minimal maintenance is needed.

Finally, as noted above, feed-forward/feed-back controls have been installed for precise control of ammonia injection on variable load engines. These controls typically use CEMS, which are relatively expensive, but which are becoming increasingly reliable. Where CEMS are not otherwise obligated to meet enhanced monitoring requirements, mapping of engine NO_X emissions as a function of load and other operating conditions may be used to determine ammonia feed rates.

Electrification, which involves the replacement of an internal combustion engine with an electric motor, may be a more costly NO_X control alternative, but offers a local reduction in NO_X emissions of 100 percent. Including NO_X generated at the utility or other power source, electrification still should afford a net emissions reduction. This alternative may be appropriate for engines near the end of their useful service lives.

Other Strategies are also available. In Connecticut, a stationary engine has been permitted with NO_X controlled through the use of an electrical plasma discharge across conventional spark plugs. This discharge allows very fuel-lean engine operation, with the potential for significant reductions from uncontrolled NO_X levels.

POTENTIAL NATIONAL EMISSIONS REDUCTION

The emissions reductions afforded by each of the control alternatives are summarize in *Table 3*.

COSTS AND COST EFFECTIVENESS

Costs derived from EPA's reciprocating engine ACT and other relevant sources are provided in *Tables 4 and 5*.

For large, continuously operated engines, capital costs for the various control alternatives range from \$6/hp for simple controls, such as air/fuel ratio adjustment and ignition timing retard, to \$30-\$50/hp for prestratified charge and three-way catalysts, to \$125/hp for selective catalytic reduction, and up to \$500/hp for low emission combustion retrofits. Given the different removal efficiencies of these controls, however, the range of removal costs per ton is much narrower, ranging from a minimum of about \$200/ton for non-selective catalytic reduction, to \$1000/ton for several of the other controls, although low emission combustion or dual-fuel engines may have a cost effectiveness of up to about \$3000/ton.

Of course, capital cost per unit of engine output will be higher on smaller engines and removal cost effectiveness will be lower on smaller and intermittently operated engines. Even on small (250-hp) engines, however, costs typically remain below \$5000 per ton of NO_X removed.

Federal Rulemaking and/or Guidance Documents

EPA released an ACT addressing NO_x emissions from stationary reciprocating internal combustion engines in July 1993.

For further information on the ACT, contact Bill Neuffer, U.S. Environmental Protection Agency, Emission Standards Division (MD-13), Research Triangle Park, NC 27711 (telephone: 919/541-5435).

State and Local Control Efforts

State RACT limits and NESCAUM recommendations for reciprocating engines are listed in *Table 6*. Typical emission limits for gas-fired rich- and lean-burn engines are 1.5-2.5 g/bhp-hr, and for oil-fired lean-burn engines, 8-9 g/bhp-hr.

As indicated in *Table 7*, emission limits in California are somewhat more stringent at less than 1 g/bhp-hr for lean-burn engines and less than 2 g/bhp-hr for rich-burn engines.

References

1. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. July 1993. *Alternative Control Techniques Document — NO_x Emissions from Stationary Reciprocating Internal Combustion Engines.*

2. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. February 1992. *Summary of NO_x Control Techniques and Their Availability and Extent of Application.*

3. Radian Corporation. July 1991. *Sourcebook: NO_x Control Technology Data.* Prepared for U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory.

4. California Air Resources Board, Stationary Source Division, and South Coast Air Quality Management District, Rule Development Division. April 29, 1987. *Technical Support Document for the Control of Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators and Process Heaters.*

5. Arthur D. Little, Inc. September 1992. *Improved Selective Catalytic NO_x Control Technology for Compressor Station Reciprocating Engines.* Prepared for Gas Research Institute.

6. U.S. Environmental Protection Agency. July 1993. *AIRS Facility Subsystem.*

Table 1

Uncontrolled NO_x Emissions from Stationary Reciprocating Internal Combustion Engines

Engine Type	Uncontrolled Emissions (g/bhp-hr)
Spark Ignition	
Natural Gas Rich-Burn	15.8
Natural Gas Lean-Burn	16.8
Compression Ignition	
Diesel	12.0
Dual Fuel	8.5

Source: EPA, July 1993.

Table 2

Estimated NO_x Emissions from Stationary Reciprocating Internal Combustion Engines

Fuel	Number of Internal Combustion Engines	National Emissions (tons/year)
Natural Gas	8,009	719,200
Diesel	841	57,100
Gasoline	96	700
Other	180	7,100
Total	9,126	784,100

Source: EPA, AIRS Executive.

Table 3

Potential Emissions Reductions from Reciprocating Internal Combustion Engines

	NO_x Reduction Potential			
Control	Rich-Burn, Gas SI	Lean-Burn, Gas SI	Lean-Burn, Diesel	Lean-Burn, Dual Fuel
Air/Fuel Adjustment	10-40	5-30	N/A	N/A
Low Emission Combustion	70-90	80-93	N/A	60-80
Ignition Timing Retard	0-40	0-20	20-30	20-30
Prestratified Charge	80-90	N/A	N/A	N/A
Non-Selective Catalytic Reduction	90-98	N/A	N/A	N/A
Selective Catalytic Reduction	N/A	90	80-90	80-90
Electrification	100	100	100	100

Source: EPA, July 1993.

Table 4

Costs of NO_x Control Technologies for Spark-Ignition Reciprocating Internal Combustion Engines[1]

		Engine Type					
		Rich-Burn			Lean-Burn		
Technology	Engine Size (hp)	Total Capital Cost ($)	Annual Cost ($)	Cost Effectiveness ($/ton)	Total Capital Cost ($)	Annual Cost ($)	Cost Effectiveness ($/ton)
Air/Fuel Adjustment[2]	250	11,000	6,000	580-870	74,000	26,000	3510-4680
	1000	16,000	15,000	350-520	78,000	31,000	1060-1420
	4000	25,000	45,000	270-400	94,000	53,000	450-600
Low Emission Combustion[2]	250	400,000	130,000	4500-5010	400,000	130,000	3970-4460
	1000	670,000	220,000	1850-2090	670,000	220,000	1610-1820
	4000	1,720,000	560,000	1190-1340	1,720,000	550,000	1030-1150
Ignition Timing Retard[2]	250	12,000	6,000	680-1130	12,000	5,000	980-4930
	1000	16,000	13,000	370-610	16,000	11,000	490-1470
	4000	25,000	38,000	270-450	25,000	30,000	340-1020
Prestratified Charge[2]	250	62,000	84,000	2670-3000		See note 3 below	
	1000	130,000	110,000	880-990		See note 3 below	
	4000	170,000	130,000	260-300		See note 3 below	
Non-Selective Catalytic Reduction[2]	250	20,000	10,000	290-310		See note 3 below	
	1000	42,000	27,000	200-220		See note 3 below	
	4000	130,000	96,000	180-190		See note 3 below	
Selective Catalytic Reduction[4]	250		See note 2 below		310,000	140,000	4280-4810
	1000		See note 2 below		340,000	180,000	1320-1490
	4000		See note 2 below		470,000	310,000	580-660

[1]Costs are estimated for engines running 8000 hours per year and are in 1993 dollars.
[2]Source: EPA, July 1993.
[3]Not applicable.
[4]Source: A.D. Little, September 1992.

Table 5

Costs of NO_x Control Technologies for Compression-Ignition Reciprocating Internal Combustion Engines[1]

Technology	Engine Size (hp)	Fuel: Diesel Total Capital Cost ($)	Diesel Annual Cost ($)	Diesel Cost Effectiveness ($/ton)	Dual Fuel Total Capital Cost ($)	Dual Fuel Annual Cost ($)	Dual Fuel Cost Effectiveness ($/ton)
Low Emission Combustion[2]	250		See note 3 below		520,000	170,000	11,370-12,990
	1000		See note 3 below		860,000	280,000	4650-5310
	4000		See note 3 below		2,210,000	710,000	2960-3390
Ignition Timing Retard[2]	250	12,000	6,000	760-1140	12,000	5,000	950-1420
	1000	16,000	13,000	420-630	16,000	11,000	470-700
	4000	25,000	40,000	310-470	25,000	29,000	320-480
Selective Catalytic Reduction[4]	250	190,000	99,000	4170-4690	190,000	98,000	5800-6530
	1000	250,000	140,000	1460-1640	250,000	130,000	1970-2210
	4000	510,000	300,000	780-880	510,000	270,000	1010-1140

[1]*Costs are estimated for engines running 8000 hours per year and are in 1993 dollars.*
[2]*Source: EPA, July 1993.*
[3]*Not applicable.*
[4]*Source: EPA, July 1993. Capital costs corrected to remove double-counting of direct installation costs in EPA ACT.*

Table 6

Selected Reciprocating Internal Combustion Engine NO_x RACT

Jurisdiction	NO_x RACT by Fuel Type (g/bhp-hr): Gas-Fired, Rich-Burn[1]	Gas-Fired, Lean-Burn[2]	Oil-Fired, Lean-Burn[2]
NESCAUM[3]	1.5	2.5	8.0
Connecticut	2.5	2.5	8.0
Louisiana[4]	2.0		
New Jersey	1.5	2.5	8.0
New York	2.0	3.0	9.0
Rhode Island	1.5	2.5	9.0
Texas[4]	2.0	Exempt	Exempt

[1] *Less than 1% oxygen.*
[2]*Equal or greater than 1% oxygen.*
[3]*The NESCAUM limits are recommendations.*
[4]*Rich-burn <0.5% O_2; Lean-burn >0.5% O_2.*

Table 7

Reciprocating Internal Combustion Engine Retrofit NO_x Limits in California

Engine Type	Emission Unit (ppm at 15% O_2)	Emission Unit (g/bhp-hr)	Engine Size (bhp)
Bay Area			
rich-burn	56	0.8	≥25
lean-burn	140	1.9	≥25
Santa Barbara County			
rich-burn	50	0.7	≥50
lean-burn	125	1.7	≥50
diesel	797	8.4	≥50
South Coast			
unspecified	36	0.5	≥50
Ventura County			
rich-burn	25	0.4	≥50
lean-burn	45	0.6	≥50
diesel	80	1.1	≥50

Kraft Pulp Mills

Summary

Kraft pulp mills produce paper pulp from wood. The approximately 200 kraft mills in the U.S. produce 50 million tons of pulp, and have aggregate NO_x emissions of 68,000 tons/year.

There are three types of NO_x sources at kraft mills. Industrial boilers are used to produce steam and power. Recovery boilers recover chemicals used in the pulping process from wood digester effluent; these boilers evaporate water from the effluent and reduce spent pulping chemicals to forms amenable to recycling. Lime kilns, the third type of NO_x source, recover calcium oxide used in the pulping chemical recovery process.

Uncontrolled kraft mill emissions are 1-5 lb NO_x/air-dried ton of pulp (ADTP) for the industrial boilers, 1.8 lb/ADTP for the recovery boiler and 0.6 lb/ADTP for the lime kiln (see *Table 1)*.

While a variety of NO_x controls are available for mill industrial boilers, little has been done to control recovery boiler or lime kiln emissions. Because recovery boilers use air staging for the chemical recovery process, they already have relatively low NO_x emissions of 0.1 lb/MMBtu on a heat input basis. Further, air staging and selective noncatalytic reduction have been demonstrated to provide additional emissions reductions.

Lime kilns should be amenable to controls used on rotary kilns in the cement industry.

Description of Source

Kraft mills produce paper pulp from wood by digesting the wood in a heated solution of sodium sulfide and sodium hydroxide (white liquor). Annual production is approximately 50 million tons of kraft pulp at approximately 200 mills. There are three significant NO_x sources at these mills — fossil-fuel- and wood-fired industrial boilers, recovery boilers and lime kilns.

Industrial Boilers at kraft mills are used to produce process steam and power. A variety of fuels are burned in these boilers, ranging from typical fossil fuels (coal, oil, gas), to bark and wood residues, to combinations of these. Fossil-fuel-fired boiler emissions are typical of those from boilers used in other industries. Bark/wood residue boilers, primarily spreader stokers, have low peak flame temperatures and produce relatively low NO_x emissions, on the order of approximately 1.76 lb per ton of wet wood residue fuel, which corresponds to 0.20 lb/MMBtu at a heat value of 9 MMBtu/ton. Combination boilers also will tend to have lower peak flame temperatures than boilers burning the corresponding fossil fuels alone, given the low heat value of bark/wood waste and, therefore, will have lower NO_X emissions. Some combination boilers do burn other fuels, such as tire-derived fuels, for which *a priori* determinations of emissions factors are not possible.

Recovery Boilers are relatively large boilers used to recover chemicals used in the kraft pulping process from the concentrated digester effluent, or black liquor. In the recovery boiler, sodium sulfate in the liquor is reduced to sodium sulfide, which forms a smelt with sodium carbonate at the bottom of this furnace. This smelt is dissolved in water in a separate smelt dissolving tank, then is treated with quicklime (calcium oxide) to convert the sodium carbonate to sodium hydroxide. The resulting solution of sodium sulfide and sodium hydroxide (white liquor) is separated from the solid calcium carbonate that forms, and is recycled to the digester. This process is illustrated in *Figure 1*.

Recovery boilers are watertube boilers and are similar in design to fossil-fuel-fired boilers. A recovery boiler is larger than a typical industrial boiler with comparable steam output as a result of the relatively low heating value of the black liquor. Black liquor is injected into the furnace of a recovery boiler through multiple burners. Combustion air is staged to create reducing conditions at the bottom of the boiler, which promotes the reduction of sulfur compounds to sulfides while allowing complete combustion of organics.

NO_X emissions from recovery boilers at mills are relatively low for two reasons. First, the low heat value of the fuel, as well as the heat used in evaporating the water in the black liquor, results in relatively low furnace temperatures so that little or no thermal NO_X is formed. Second, air staging in the furnace, used to ensure reduction of sodium sulfate to sodium sulfide in an oxygen-poor region at the bottom of the furnace, also minimizes generation of NO_X in primary combustion. This air staging is analogous to the use of overfire air in fossil fuel-fired boilers.

Emissions factors for recovery boilers range from 0.9 to 3.3 lb NO_X/ADTP, with a mean of 1.8 lb/ADTP, or 0.091 lb/MMBtu. Boilers built after 1980 are run with higher solids content black liquor (up to about 80 percent solids by weight, compared with 60-70 percent in older boilers) and have mean emissions factors of 2.25 lb/ADTP, or 0.13 lb/MMBtu. Emissions will vary with operational factors and the nitrogen content of the wood being processed, with hard woods having higher nitrogen contents than soft woods.

Lime Kilns are the third NO_X source at kraft pulp mills. To recover the calcium oxide consumed in the smelt dissolving tank, the calcium carbonate is washed, dried and then calcined in a lime kiln, which is typically a rotary kiln fired with fossil fuels (normally natural gas or residual oil). Lime kiln NO_X emissions range from 0.08 to 9.0 lb/ton calcium oxide.

STAPPA/ALAPCO
Recommendation

▶ Agencies can obtain NO_X reductions from kraft pulp mills by regulating industrial boilers, recovery boilers and lime kilns. Industrial boilers at kraft pulp mills can meet emission limits comparable to other industrial boilers (see recommendation for Industrial and Commercial Boilers). While most recovery boilers are adequately controlled, additional reductions could be achieved with selective noncatalytic reduction, although there is limited experience. Lime kilns can be regulated in a manner similar to rotary kilns used in the cement industry (see chapter on Cement Kilns).

Emissions Per Unit Output

Based on data collected by EPA and the paper industry, coal-, oil- and gas-fired industrial boilers produce approximately two-thirds of kraft mill NO_X emissions. Recovery boilers contribute approximately 17 percent of these emissions, and lime kilns 5 percent.

National Emissions Estimate

According to EPA, total NO_X emissions from all kraft mill sources in the U.S. are approximately 68,400 tons/year. Total emissions from paper, pulp and paperboard mills are approximately 360,400 tons annually.

Geographic Distribution of Sources and Emissions

Table 2 provides a state-by-state breakdown of the number of paper, pulp and paperboard mills, along with the annual statewide NO_X emissions from these sources. As the table shows, significant numbers of mills are located in the south (Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee and Virginia) and the midwest and northeast (Ohio, Wisconsin, Pennsylvania, Maine and New York). A significant number of mills are also located in Washington.

Available Control Strategies

Control strategies appropriate for industrial boilers will also be appropriate for kraft mill power boilers and steam generators.

Two strategies have been demonstrated for the control of NO_x emissions from recovery boilers — low excess air/air staging and SNCR. While recovery boiler NO_x emissions are largely fuel derived, given low furnace temperatures, strategies such as switching to lower nitrogen content woods are not practical.

Low Excess Air and Air Staging, in combination, result in moderate reductions in NO_x emissions. Each 1-percent decrease in economizer excess oxygen level reduces NO_x emissions by approximately 10-20 percent. Modifying the air staging from baseline operation often appears to provide further, boiler-dependent emissions reductions. Both parameters may influence recovery boiler function, and a detailed study at each boiler may be necessary to determine the extent to which this strategy may be implemented.

Selective Noncatalytic Reduction (SNCR) using urea (NO_xOUT^{TM} process) has been demonstrated at a 900-MMBtu/hr recovery furnace in Sweden. Controlled emissions of approximately 0.044 lb/MMBtu were obtained at full boiler load in this short-term demonstration, corresponding to an emissions reduction of over 60 percent from an uncontrolled level of 0.125 lb/MMBtu. Ammonia slip was approximately 11 ppm and nitrous oxide emissions increased only to about 1 ppm. No effect of the SNCR system on overall boiler operation was observed, although approximately 0.4 percent of input ammonia was trapped in the fly ash leaving the boiler. Based on these results, SNCR appears to be an effective control for recovery boiler NO_x emissions.

Lime kilns are similar to the rotary kilns used in the cement industry and should be amenable to the use of similar NO_x controls, as discussed in the next chapter of this document.

Potential National Emissions Reduction

Given that recovery boilers and lime kilns are minor contributors to kraft mill NO_x emissions, the bulk of emissions reductions must come from the fossil fuel and other boilers that are the major contributors. Emissions reductions of approximately 50 percent should be possible from these boilers.

Costs and Cost Effectiveness

Based upon the Swedish demonstration, the capital cost of installing SNCR on a recovery boiler is expected to be about \$2800-\$3500 per MMBtu/hr of capacity (\$7.5-\$9.6 per ton of bleached pulp capacity). SNCR cost effectiveness will be \$1000-\$1500/ton of NO_x removed.

Federal Rulemaking and/or Guidance Documents

There are no federal regulations addressing NO_x emissions from pulp mills.

State and Local Control Efforts

There are no state or local regulations governing NO_x from pulp mills.

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7. U.S. Environmental Protection Agency. July 1993. *AIRS Facility Subsystem.*

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Figure 1

Kraft Mill Flow Diagram

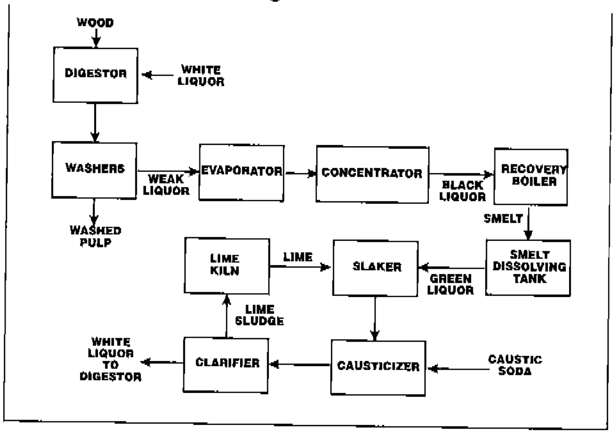

Table 1

Uncontrolled Kraft Mill Emissions

Source	Uncontrolled Emissions: Heat Input (lb/MMBtu)	Uncontrolled Emissions: Output (lb/ADTP)
Boilers		
Coal	0.53	4.9
Oil	0.38	1.1
Gas	0.23	1.9
Wood	0.20	1.33
Recovery Boilers	0.091	1.8
Lime Kilns	0.27	0.56

Source: Pinkerton, 1993.

Table 2

Paper, Pulp and Paperboard Mills

State	Plants	NO_x Emissions (tons/year)	Percent of Total Stationary Source NO_x Emissions
Alabama	13	32,200	9.8%
Alaska	2	700	2.8%
Arizona	1	4,500	4.1%
Arkansas	7	11,000	10.8%
California	2	300	0.7%
Connecticut	1	400	0.9%
Florida	8	12,300	3.6%
Georgia	14	35,500	11.6%
Idaho	1	900	7.7%
Illinois	2	2,800	0.5%
Indiana	2	800	0.1%
Iowa	1	205	0.2%
Kansas	1	200	0.1%
Kentucky	3	1,300	0.4%
Louisiana	9	31,300	7.4%
Maine	15	19,300	55.2%
Maryland	1	4,600	3.2%
Massachusetts	3	700	0.6%
Michigan	3	1800	12.3%
Minnesota	5	4,700	3.2%
Mississippi	6	7,300	9.6%
Montana	1	2,000	3.1%
New Hampshire	3	1,800	6.2%
New Jersey	3	2,800	2.0%
New York	11	5,200	2.1%
North Carolina	6	17,000	5.7%
Ohio	12	46,600	7.0%
Oklahoma	2	3,600	1.9%
Oregon	3	600	5.3%
Pennsylvania	14	16,600	2.9%
South Carolina	6	14,800	10.5%
Tennessee	6	13,200	3.9%
Texas	6	8,900	0.9%
Vermont	1	100	50.5%
Virginia	6	14,300	9.4%
Washington	15	13,000	23.9%
West Virginia	1	100	<0.1%
Wisconsin	26	27,000	17.5%

Source: EPA, AIRS Executive, January 28, 1994.

Cement Kilns

Summary

The U.S. cement industry uses the nation's 213 cement kilns to produce about 81 million tons of cement a year. Nearly all NO_X emissions from cement manufacturing are the result of the high process temperatures out of these kilns.

Among the states, California, Texas, Pennsylvania, Michigan, Missouri and Alabama are the top cement producers. All of these states have capacities greater than 4 million tons.

There are four basic kiln types which together emit an estimated 118,000 to 146,000 tons of NO_X annually. Emission factors, on average, range from 3.4-9.7 lbs NO_X/ton of product, depending on the type of kiln and site-specific factors.

A number of NO_X control strategies are available, with reduction efficiencies ranging from 20-90 percent. At a typical kiln, these controls can achieve NO_X reductions of hundreds of tons a year, compared to uncontrolled levels.

EPA estimates of cost effectiveness ($/ton of NO_X removed) range from $830-$1330 for low NO_X burners, to $450-$610 for mid-kiln firing, to $790-$930 for urea-based SNCR, to $3140-$4870 for SCR.

Description of Source

Cement kilns are used by the cement industry in the production of cement. Portland cement, used in almost all construction applications, is the industry's primary product. Essentially all of the NO_X emissions associated with cement manufacturing are generated in the kilns because of high process temperatures.

To make cement, raw materials such as limestone, cement rock, sand, iron ore, clay and shale are crushed, blended and fed into a kiln. These materials are then heated in the kiln to temperatures above 2900°F to initiate a chemical reaction (called "fusion") that produces cement "clinker," a round, marble-sized, glass-hard material. The clinker is then cooled, mixed with gypsum and ground to produce cement.

Nearly all cement clinker is produced in large rotary kiln systems. The rotary kiln is a refractory brick-lined cylindrical steel shell equipped with an electrical drive to turn it at 1-3 rpm, through which hot combustion gases flow countercurrently to the feed materials. The kiln can be fired with coal, oil, natural gas, waste or a combination of these fuels. Currently, most cement plants (over 75 percent) are coal-fired.

There are four types of kilns in use — long wet kilns, long dry kilns, kilns with a preheater and kilns with a precalciner. The long wet and dry kilns and most preheater kilns have only one fuel combustion zone, whereas the newer precalciner kilns and preheater kilns with a riser duct have two fuel combustion zones.

In a wet kiln, the ground raw materials are suspended in water to form a slurry. In a dry kiln, the raw materials are dried to a powder. Newer U.S. cement plants normally use the dry process because of its lower energy requirement.

Because the typical operating temperatures of these kilns differ, the NO_x formation mechanisms also differ among these kiln types. In a primary combustion zone at the hot end of a kiln, the high temperatures lead to predominantly thermal NO_x formation. In the secondary combustion zone, however, lower gas-phase temperatures suppress thermal NO_x formation. Energy efficiency is also important in reducing NO_x emissions; for example, a high thermal efficiency means less heat and fuel are consumed and, therefore, less NO_x is produced.

Emissions Per Unit Output

Average emission factors for the four different types of cement kilns discussed above are identified in *Table 1*. As shown, emission factors (lb/ton of clinker) range from 3.4 for precalciner kilns to 9.7 for long wet kilns.

Both EPA's draft ACT document and the *Air Pollution Engineering Manual* from the Air & Waste Management Association, however, caution that due to the diversity of cement plant design and operation, NO_x emission factors should be viewed as encompassing a wide range.

National Emissions Estimate

In its *National Air Pollutant Emission Trends, 1900-1992*, published in 1993, EPA's estimate of annual NO_x emissions from cement manufacturing is 118,000 tons.

According to EPA's AIRS Executive database, 1993 NO_x emissions from 98 "hydraulic cement plants" totaled 146,203 tons. EPA's AIRS Facility Subsystem breaks out the total emissions from dry process cement kilns (78,975 tons per year) and wet process cement kilns (46,025 tons per year) for a total of 125,000 tons of NO_x per year.

Therefore, total NO_x emissions appear to range between approximately 118,000 and 146,200 tons per year.

Geographic Distribution of Sources and Emissions

Recent data show a total of 213 cement kilns at approximately 100 plants in the U.S., producing about 81 million tons of Portland cement a year. The industry's annual clinker capacity has steadily declined from the 1973 peak of 414 kilns with a capacity of 91 million tons. (Clinker production is being exported).

STAPPA/ALAPCO
Recommendation

▶ Agencies should consider requiring combustion controls on cement kilns, which can reduce uncontrolled emissions by up to 40 percent. Technologies for post-combustion controls — SNCR — are being demonstrated in the United States and could achieve NO_x reductions up to 70 percent for certain cement kiln processes.

Table 2 profiles the clinker-producing capacity in the U.S. by state. California, Texas, Pennsylvania, Michigan, Missouri, and Alabama all have clinker capacities greater than 4 million tons.

Table 3 details the number of cement plants by state and their emissions. Similar to the data in *Table 2*, EPA's AIRS Executive data show concentrations of cement plants in Alabama, Florida, Illinois, Indiana, Iowa, Missouri, New York, Pennsylvania, South Carolina and Texas.

Available Control Strategies

Combustion and post-combustion controls are available for controlling NO_x emissions from cement kilns.

Combustion Controls. Process control approaches, which provide optimum kiln operating conditions, thereby increasing energy efficiency and productivity, minimize NO_x emissions. Such approaches, however, are generally considered necessary for proper kiln operation and are usually viewed as setting baseline NO_x emissions, not as NO_x control techniques *per se*.

Some kiln operators, however, do rely on process monitoring and control to meet NO_x emission permit levels. Such process controls include less intense "lazy" flames in the kiln burning zone, increased fuel input in the flash calciner furnace, preheating the raw feed, using raw feed additives and recycling cement dust.

Limited data exist on the use of low NO_x burners in cement kilns, although staging of combustion air is a possible NO_x reduction technique in precalciner kilns. In the first stage, fuel combustion occurs in a high-temperature, fuel-rich environment. Fuel combustion is completed in the fuel-lean, low temperature environment of the second stage. By controlling the available oxygen and temperature, low NO_X burners can reduce NO_X formation in the flame zone. Although low NO_X burners are used in some European cement kilns, very few have been installed in U.S. cement kilns.

Secondary combustion of fuel ("mid-kiln" firing) is available for long dry and wet kilns to achieve NO_X reductions of 20-40 percent, although this technology has not been applied extensively. Secondary fuel combustion is, however, inherently present in all precalciner kilns and preheater kilns with riser duct firing; such kilns produce less NO_X than long dry kilns.

Experimental studies also show that changing the primary kiln fuel from natural gas to coal can reduce the flame temperatures, resulting in significantly lower thermal NO_X emissions. A number of cement kilns have switched from gas to coal; currently over 75 percent of the primary fuel cement kilns burn coal.

Post-Combustion Controls. In early 1994, an SNCR vendor announced the first demonstration of urea-based SNCR on a U.S. cement kiln/calciner process. The objective was to reduce NO_X emissions below 422 pph; test results indicated that reductions well below this level were achieved.

EPA's draft ACT document for cement manufacturing concludes that SNCR is not applicable to long wet and dry kilns due to difficulties involved in continuous injection of reducing agents. For preheater and precalciner kilns, however, potential SNCR NO_X removal efficiencies are reported at 30-70 percent.

There are no reported installations of SCR in U.S. cement kilns, although application of this technology is theoretically possible and tests in the late 1970s showed removal efficiencies of 75-98 percent. The presence of alkalies and lime in the exhaust gases of cement plants, however, is an issue to be addressed. SCR would have to be installed after particulate collection, and flue gas reheating would be necessary to increase the flue gas temperatures to the appropriate SCR operating level.

Table 4 identifies the NO_X reduction potentials of these controls.

Potential National Emissions Reduction

NO_X emissions can be reduced by hundreds of tons a year at individual facilities by retrofitting available control technologies. Since data is not available on the extent to which these controls are already installed on U.S. cement kilns, it is not possible to quantify the national emissions reduction potential. It would seem likely, however, that widespread retrofit of NO_X controls would reduce NO_X emissions from cement kilns by tens of thousands of tons a year.

Costs and Cost Effectiveness

One SNCR vendor estimates that the capital cost (including equipment, engineering, installation, license fee, service contract, start-up, optimization and training) of applying the technology to a cement kiln, based on a demonstration in late 1993, would be a consistent $0.08 per ton on a 15-year life, 85-percent average plant capacity of 100 tons/hr normal output.

This SNCR vendor also estimated the operating costs, which are a direct function of the firing rate in the kiln necessary to process the raw material mix. Raw material variations change the firing rate and NO_X levels are either below the permit level, where no chemical is required, or above, where the chemical rate will be needed to lower the NO_X emissions to below the permit level. To maintain NO_X emissions at 400 lb/hr, the operating cost of the SNCR system on the subject kiln was estimated at $0.14 per ton.

As shown in *Table 5*, EPA's 1994 draft ACT document estimates the total capital costs and cost effectiveness of several control technologies for eight model plants. As indicated, cost effectiveness ($/ton of NO_X removed) ranges from $830-$1330 for low NO_X burners, to $450-$610 for mid-kiln firing, to $790-$930 for urea-based SNCR, to $3140-$4870 for SCR. For each kiln type, the cost effectiveness of each control strategy varies inversely with kiln capacity.

In 1991, the SCAQMD estimated the cost effectiveness of using SCR to reduce cement kiln NO_X emissions by 85 percent to be $1300/ton of NO_X reduced.

Federal Rulemaking and/or Guidance Documents

EPA is developing an ACT document entitled, *Control of NO_X Emissions from Cement Manufacturing*. The first draft is dated February 1993 and final drafts of some chapters were available as of March 1994.

For further information on the ACT, contact Bill Neuffer, U.S. Environmental Protection Agency, Emissions Standards Division (MD-13), Research Triangle Park, NC 27711 (telephone 919/541-5435).

State and Local Control Efforts

The South Coast Air Quality Management District (Rule 1112) requires affected cement kilns to limit NO_X emissions to 11.6 lb/ton of clinker produced (24-hour avering boiler feed water in an economizer unit. Average furnace exit temperatures for these industrial boilers are estimated to be 2200°F, with peak furnace temperatures occurring in excess of 2810°F.

Process Heaters. Similar to an industrial boiler, a process heater produces heat through fuel combustion. This heat is transferred by radiation and convection to fluids contained in tubes. Process heaters are used in organic chemical manufacturing to drive thermal reactions, such as thermal cracking. They can also be used as feed preheaters and as reboilers for some distillation operations. Fuels used in process heaters include natural gas and various grades of fuel oil. However, it is estimated that gaseous fuels account for about 90 percent of the energy consumed by process heaters.

Process heater designs vary depending on the application. Generally, however, the heat radiant section consists of the burner(s), the firebox and a row of tubular coils containing the process fluid. For increased energy efficiency, most heaters also contain a convection section in which heat is recovered from hot combustion gases by convective heat transfer to the process fluid. In the organic chemical industry, process heater applications can be broadly classified based on firebox temperature: 1) low firebox temperature applications, such as feed preheaters and reboilers; 2) medium firebox temperature applications, such as stream superheaters; and 3) high firebox temperature applications, such as pyrolysis furnaces and steam-hydrocarbon reformers. This translates into estimated firebox temperatures of between approximately 750°F for preheaters and reboilers, and 2300°F for pyrolysis furnaces. Heater type, firebox temperatures and energy requirements of some of the major fired heater applications in the organic chemical industry are identified in *Table 1*.

Emissions Per Unit Output

For listings of emission factors, see the chapters on Industrial and Commercial Boilers and Process Heaters.

National Emissions Estimate

According to EPA's *AIRS Executive* database, industrial boilers and process heaters used in the organic chemical industry generate approximately 268,000 tons of NO_x per year.

Geographic Distribution of Sources and Emissions

Table 2 lists the geographic location of and emissions from the estimated 124 largest organic chemical plants.

STAPPA/ALAPCO *Recommendation*

▶ NO_x emissions from organic chemical plants are regulated by imposing controls on industrial boilers and process heaters at these facilities.

As indicated, organic chemical plants are concentrated in Illinois, New Jersey, Texas, Virginia and West Virginia.

Available Control Strategies

A full description of emission control strategies and associated cost calculations can be found in the chapters on Industrial and Commercial Boilers and Process Heaters.

Federal Rulemaking and/or Guidance Documents

Because NO_x emissions from organic chemical manufacturing plants are generated almost exclusively through the use of industrial boilers and process heaters, rather than through non-combustion-related chemical reactions, NO_x control regulations are not applied directly to organic chemical plants as a unique group. Federal regulations for industrial boilers and process heaters are described in the chapters on Industrial and Commercial Boilers and Process Heaters.

State and Local Control Efforts

There are no state or local regulations that specifically address organic chemical plants; however, since NO_x emissions from this source category are generated mostly through the use of industrial boilers and process heaters, state and local agencies have established regulations for these sources, as described in the chapters on Industrial and Commercial Boilers and Process Heaters.

References

1. U.S. Environmental Protection Agency. August 1993. *Control Techniques Guideline — Control of Volatile Organic Compound Emissions from Reactor Processes and Distillation Operations Processes in the Synthetic Organic Chemical Manufacturing Industry.*

2. U.S. Environmental Protection Agency. February 1993. *Alternative Control Techniques Document — NO_x Emissions from Process Heaters.*

3. U.S. Environmental Protection Agency. October 1993. *AIRS Executive.*

4. U.S. Environmental Protection Agency. July 1993. *AIRS Facility Subsystem.*

5. U.S. Environmental Protection Agency. January 28, 1994. *AIRS Executive.*

Table 1

Energy Requirements of Major Fired Heater Applications in the Organic Chemical Industry

Chemical	Process	Heater Type	Firebox Temperature (°F)	1985 Fired Heater Energy Requirement (10^{12} Btu/yr)
Low- and Medium-Temperature Applications				
Benzene	Reformate Extraction	Reboiler	700	64.8
Styrene	Ethylbenzene Dehydrogenation	Steam Superheater	1,500-1,600	32.1
P-Xylene	Xylene Isomerization	Reactor Fired Preheater	N/A	13.0
Dimethyl Terephthalate	Reaction of P-Xylene and Methanol	Preheater, Hot-Oil Furnace	480-540	11.1
Butadiene	Butylene Dehydrogenation	Preheater, Reboiler	1,100	2.6
Ethanol (synthetic)	Ethylene Hydration	Preheater	750	1.3
Acetone	Various	Hot-Oil Furnace	N/A	0.8
High-Temperature Applications				
Ethylene/Propylene	Thermal Cracking	Pyrolysis Furnace	1,900-2,300	337.9
Methanol	Hydrocarbon Reforming	Steam Hydrocarbon	1,000-2,000	25.7

Source: EPA, February 1993.

Table 2

Organic Chemical Plants

State	Plants	NO_x Emissions (tons/year)	Percent of Total Stationary Source Emissions
Alabama	3	2,200	0.7%
Arkansas	1	3,800	3.8%
Delaware	1	100	0.2%
Florida	1	100	<0.1%
Georgia	2	1,700	0.6%
Illinois	12	7,400	1.4%
Indiana	1	1,000	0.2%
Iowa	1	100	0.1%
Kentucky	3	800	0.2%
Louisiana	21	45,600	10.8%
Missouri	7	2,600	0.8%
Nebraska	1	100	0.1%
New Jersey	6	11,400	7.9%
New York	1	100	<0.4%
North Carolina	2	900	0.3%
Ohio	4	3,300	0.5%
Oregon	1	300	2.5%
Pennsylvania	2	800	0.1%
South Carolina	2	500	0.3%
Tennessee	3	500	<0.1%
Texas	49	162,400	16.6%
Virginia	2	17,500	11.6%
Washington	1	100	0.25%
West Virginia	9	5,000	1.2%
Total	136	268,000	

Source: EPA, AIRS Executive, January 28, 1994.

Petroleum Refineries

Summary

Petroleum refineries convert crude oil to gasoline, diesel and jet fuels, lubricating oils and other products. The approximately 190 operating U.S. refineries have the capacity to process over 15 million barrels of crude oil per day and emit about 372,000 tons/year of NO_x.

Several refinery sources produce significant NO_x emissions. Fossil-fuel-fired process heaters and boilers are used throughout the refinery. CO boilers are used to burn the off-gases from fluid catalytic cracking unit regenerators, and have uncontrolled NO_x emissions of 230-300 ppm at 3 percent oxygen. Fluid catalytic cracking unit regenerators themselves produce NO_x at an uncontrolled rate of 71 pounds per barrel (lb/bbl) of feed.

Available NO_x controls for refinery boilers and process heaters are similar to those used in other industries and have similar costs and cost effectiveness. In particular, SNCR has been used to control CO boiler emission to below 50 ppm.

Description of Source

Petroleum refineries convert crude oil to a large number of salable products. Foremost among these are gasoline, diesel and other fuel oils, jet fuels, lubricating oils and petrochemical products. There are between 164 and 190 operating refineries in the U.S., with the capacity to process over 15 million barrels per day of crude oil.

Significant sources of NO_x emissions at refineries include boilers and process heaters, fluid catalytic cracking unit regenerators and tail gas incinerators. These processes generate approximately 371,800 tons of NO_x annually.

Process or Refinery Heaters are used throughout the refinery. Typical applications include heating crude oil for distillation, preheating feeds for coking, catalytic cracking, hydrodesulfurization, and catalytic reforming, and providing heat for thermal cracking and visbreaking. There are over 3000 process heaters in use at refineries, with a mean heat input capacity of 72 MMBtu/hr.

Boilers are used to generate process steam for various refinery operations. While most boilers burn fossil fuel, some burn process waste gases. For example, CO boilers burn the off-gases from fluid catalytic cracking unit regenerators. These off-gases contain 1-10 percent CO, and normally are fired with supplemental fuel. CO boiler uncontrolled NO_x emissions range from 230-300 ppm (dry, 3 percent O_2).

Fluid Catalytic Cracking Units (FCCUs) convert gas and oil into high-octane gasoline and other components. A process heater is used to preheat FCCU feed, which is mixed with a catalyst at the bottom of a riser — a tall up-flow reactor. At the top of the riser, the catalyst is separated from the product stream and sent to the regenerator, where coke is burned off of the catalyst. The regenerator both restores the catalyst activity and reheats the catalyst before it is returned to the riser.

Regenerators can be significant sources of NO_x. Essentially all of this NO_x is fuel NO_x; regenerator temperatures of 1100°F-1250°F are too low for the formation of thermal NO_x. While AP-42 suggests total FCCU NO_x emissions of 71 lb/bbl of feed, regenerator emissions are variable depending upon the feed used. Common emissions are on the order of 50-400 ppm.

Tail Gas Incinerators are thermal oxidation units used to destroy low heating value waste gases produced in desulfurization processes. Tail gas sulfur compounds, including hydrogen sulfide, are converted to sulfur oxides in these incinerators, and hydrocarbon compounds are oxidized to CO_2. Hot (1800°F) flames in tail gas incinerators produce thermal NO_x, which when added to fuel NO_xresults in uncontrolled emissions of up to 200 ppm.

Emissions Per Unit Output

Fluid catalytic cracking unit emissions are 71 lb/bbl.

National Emissions Estimate

According to EPA, total national NO_x emissions from the major operating petroleum refineries are 372,000 tons per year. The three major sources of NO_x — process heaters, fluid catalytic cracking units and blowdown systems — emit a total of approximately 237,000 tons of NO_x annually. *Table 1* shows the breakdown of total emissions from these three processes.

Geographic Distribution of Sources and Emissions

EPA's *AIRS Executive* database identifies a total of 164 major petroleum refineries, emitting at least 100 tons of NO_x per year in the U.S. These sources emit a total of approximately 372,000 tons annually. *Table 2* lists the number of major refineries and emissions by state, as described in the *AIRS Executive* database. As indicated, significant concentrations of refineries are located in California, Illinois, Louisiana, Pennsylvania, Oklahoma and Texas.

STAPPA/ALAPCO *Recommendation*

▶ State and local agencies can achieve significant NO_x reductions from petroleum refineries. Reductions from refinery boilers and process heaters can be achieved in a manner comparable to other industries. Fluid catalytic cracking units can reduce emissions by controlling CO boilers. Limits of 50-200 ppm have been achieved using selective noncatalytic reduction (SNCR). Tail gas incinerators can achieve limits of 50 ppm or lower using SNCR or low NO_x burners.

Available Control Strategies

Available options for controlling fossil-fuel-burning refinery boiler and process heater NO_x emissions are described in other chapters of this document. These options also should be suitable for CO boilers. In particular, controlled emissions of 50-220 ppm have been achieved on CO boilers retrofitted with SNCR.

As noted above, fluid catalytic cracking unit regenerator off-gases normally contain CO and often are fed to a CO boiler. One option for controlling regenerator NO_x, therefore, would be installation of NO_x controls on CO boilers.

Other options are available for directly limiting NO_x emissions from the fluid catalytic cracking unit regenerator. These include minimizing excess air in the flue gas, maintaining a high flue gas CO content or operating with a higher catalyst carbon loading, all of which would create reducing conditions in the regenerator, leading to minimized formation/destruction of NO_x.

Ammonia-based SNCR has been used in short-term demonstrations on fluid catalytic cracking unit regenerators in Germany and Japan, however, little information is available in these demonstrations. Significant ammonia slip (50 ppm) accompanied NO_x reductions in at least one case.

Catalyst manufacturers also are investigating alternative cracking catalyst formulations for reduced NO_x emissions.

Tail gas incinerator NO_x emissions may be reduced to 50 ppm and below using low NO_x burners or SNCR.

Potential National Emissions Reduction

Given the variety of refinery NO_x sources it is difficult to estimate a potential national emissions reduction.

Costs and Cost Effectiveness

Control costs for refinery sources should be similar to those for other industrial sources.

Federal Rulemaking and/or Guidance Documents

No federal regulations cover NO_x emissions from petroleum refineries.

State and Local Control Efforts

Several states have adopted boiler and process heater NO_x limits that would cover refinery sources. These limits are summarized in the appropriate chapters of this document.

Further, two local air quality management districts in California have adopted rules specific to refineries. South Coast (Los Angeles) Rule 1109 limits refinery boiler and process heater emissions to 0.03 lb/MMBtu on units with greater than 40 MMBtu/hr heat input. This rule specifically includes CO boilers and fluid catalytic cracking unit regenerators.

Bay Area (San Francisco) Regulation 9, Rule 10 applies a 0.03-lb/MMBtu refinery-wide average NO_x emission limit to boilers and process heaters. A separate 150-ppm NO_x limit applies to CO boilers.

References

1. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. February 1993. *Alternative Control Techniques Document — NO_x Emissions from Process Heaters.*

2. Air & Waste Management Association. 1992. *Air Pollution Engineering Manual.*

3. Bay Area Air Quality Management District. March 2, 1993. *Draft Staff Report. Regulation 9, Rule 10. Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators, and Process Heaters in Petroleum Refineries.*

4. California Air Resources Board. July 18, 1993. *Determination of Reasonably Available Control Technology and Best Available Retrofit and Control Technology to Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters.*

5. U.S. Environmental Protection Agency. July 1993. *AIRS Facility Subsystem.*

6. U.S. Environmental Protection Agency. January 28, 1994. *AIRS Executive.*

Table 1

Total Annual NO_x Emissions from Refinery Sources

Process	Tons Per Year
Process Heaters	165,000
Fluid Catalytic Cracking Units	41,000
Blowdown Systems	31,000
Total	237,000

Source: EPA, AIRS.

Table 2

Distribution of Major Source Petroleum Refineries in the United States

State	Plants	NO_x Emissions (tons/year)	Percent of Total State Stationary Source NO_x Emissions
Alabama	3	1,600	0.5%
Arkansas	1	900	0.9%
California	13	15,000	32.7%
Colorado	3	1,200	1.0%
Delaware	1	18,000	38.7%
Hawaii	4	3,900	10.8%
Illinois	7	52,700	9.6%
Indiana	3	6,000	1.1%
Kansas	8	11,200	5.4%
Louisiana	16	44,200	10.5%
Minnesota	2	4,300	3.0%
Mississippi	2	5,100	6.8%
Montana	3	4,800	7.6%
New Jersey	6	6,600	4.6%
New Mexico	3	1,800	1.4%
North Dakota	1	1,500	1.2%
Ohio	4	6,700	1.0%
Oklahoma	8	14,900	7.9%
Pennsylvania	11	15,300	2.6%
South Carolina	1	100	<0.1%
Tennessee	1	600	0.2%
Texas	37	136,300	14.0%
Utah	10	5,700	6.5%
Virginia	1	600	0.4%
Washington	5	7,000	12.9%
West Virginia	4	2,000	0.5%
Wisconsin	1	600	0.4%
Wyoming	5	3,100	2.5%

Source: EPA, AIRS Executive, January 28, 1994.

Residential Space and Water Heaters

SUMMARY

The U.S. Department of Energy estimated that in 1990 there were over 50.3 million residential gas-fueled water heaters, 10.4 million oil-fired space heaters and 52.7 million gas-fired space heaters in the U.S. The NO_X emissions rates are a function of flame temperature and the combustion product cooling rate.

Replacement of residential space heaters and water heaters with equipment designed to produce lower emissions of NO_X is the most viable approach for achieving significant reductions of NO_X from these sources.

A number of air regulatory agencies have set NO_X emissions limits from new water heaters and space heaters at 0.09 lb/MMBtu of heat output. Such requirements are estimated to generate 50 percent or more NO_X emission reductions. Commercially available equipment can achieve this level of control. Space heaters and water heaters with high energy efficiency, electric heat pumps and solar-assisted gas water heaters are capable of achieving even greater reductions in NO_X emissions. Indeed, growing consumer preferences for highly energy-efficient equipment will facilitate reduction of NO_X emissions from these sources.

DESCRIPTION OF SOURCE

Space Heaters. Residential space heaters are self-contained, natural-gas- or oil-fired forced-air central furnaces that provide heat for comfort in residences. Natural-gas-fired residential space heating units generally employ single-port upshot or tubular multi-point burners. Oil-fired (distillate oil) units usually use high-pressure atomizing gun-type burners. These units typically have heating input ratings of less than 175,000 Btu/hr and have an average life of about 20 years. Over 60 percent of existing furnaces are 10 years or older; over 30 percent are 20 years or older.

In 1992, over 2.1 million gas furnaces were shipped by manufacturers. Over 20 percent of these units were high-efficiency furnaces. In 1992, the weighted average efficiency of shipped gas furnaces was 80 percent Annual Fuel Utilization Efficiency (AFUE). The highest AFUE rating for a commercially available furnace in 1992 was 96.6 percent.

Gas-Fired Water Heaters. Residential water heaters are small, low-pressure, gas-fired furnace tanks that heat water to a thermostatically-controlled temperature for delivery on demand. Combustion air is provided

STAPPA/ALAPCO *Recommendation*

▶ Agencies should consider imposing NO_X limits on new residential space and water heaters at 0.09 lb/MMBtu of heat output — a level that is similar to what many air quality agencies are currently requiring. Additionally, agencies may wish to consider incentives to encourage the turnover of older space and water heaters.

in a water heater by natural draft. Gas-fired water heaters use fuel at an average rate of about 65 cubic feet per day and have an average life of 10 years. Residential water heaters range in size up to about 75,000 Btu/hr gross heat input duty.

Emissions Per Unit Output

In 1991, the Santa Barbara County Air Pollution Control District in California estimated the average NO_X emissions from gas-fired water heaters that were currently in use to be approximately 0.1 lb per million Btu of net heat output and typical NO_X emissions from existing space heaters ranging up to 0.13 MMBtu gross heat output.

National Emissions Estimate

EPA does not report nationwide NO_X emissions from residential space and water heaters. According to the U.S. Department of Energy, in 1990 natural-gas-fired water heaters consumed 1.16 quadrillion Btus, gas-fired space heaters consumed 3.37 quadrillion Btus and oil-fired space heaters consumed 0.87 quadrillion Btus. Using the emission factors cited above, these consumption levels would translate approximately into nationwide annual NO_X emissions levels of 219,000 tons from gas-fired space heaters, 57,500 tons from oil-fired space heaters and 58,000 tons from gas-fired waterheaters, for a total of 334,500.

Geographic Distribution of Sources and Emissions

EPA has not developed an emissions inventory for residential water and space heaters. *Table 1* identifies the number of water and space heaters, together with the energy consumption by region.

Available Control Strategies

Space Heaters. Replacement of heating equipment with equipment designed to produce lower emissions of NO_X is the most cost effective means for achieving significant reductions in NO_X emissions from space heaters. NO_X emissions of no more than 0.09 pounds of NO_X per MMBtu of useful heat output — the current regulatory NO_X limit for several local jurisdictions — have been demonstrated with new low NO_X burner and low excess air tuning techniques.

NO_X emissions can also be reduced through the use of heat transfer modules, which employ a combination burner and heat exchanger. Heat transfer modules are top-of-the-line models and at present may not be economically feasible for most sources. However, the cost may be reduced in the future. A cost-effective alternative to a gas-fired space heater is the electric heat pump.

A summary of the major types of residential space heating equipment alternatives for gas-fired units is provided in *Table 2*. Use of equipment that is currently available can reduce NO_X by up to 70 to 80 percent over conventional units. Further, equipment under research may have the capability of achieving even greater levels of control.

The Santa Barbara County Air Pollution Control District calculated the cost effectiveness of two low NO_X burner technologies, as shown in *Tables 3 and 4*. CARB estimated the cost effectiveness of a regulation based on a 0.09-lb/MMBtu NO_X limit to be $1600 per ton.

The Alliance for Energy, a nonprofit coalition of business, government, consumer and environmental organizations and individuals, estimates that a high-efficiency space heater over a standard 78-percent AFUE unit will add about $500 to the purchase and installation costs. The payback time to recover the $500 cost difference is two to seven years, depending on usage.

Gas-Fired Water Heaters. NO_X emissions from natural-gas-fired water heaters can be controlled by low NO_X burners and solar-assisted water heating. Development work is underway to provide additional NO_X emissions reductions from water heaters.

Low NO_X water heaters can reduce NO_X emissions by 50 percent or more. Solar-assisted heaters using non-concentrating solar collectors, such as a flat-plate solar panel, are capable of providing significant domestic water heating capabilities. Conventional natural-gas-fired water heaters would continue to be used to supplement the solar component. For example, the South Coast Air Quality Management District estimated that solar power could provide 52 percent of the energy needed for a water heater in southern California.

Stock vent valves or flue dampers are used in commercial water heaters to reduce stored heat lost through convection of the gases through the stock while the heater is in a stand-by mode. These devices — which cut off the flow of escaping gases during stand-by, thereby reducing heat loss and, in turn, reducing fuel consumption and NO_X emissions — could be applied to residential water heaters, but have not been marketed as residential water heaters.

A recently completed demonstration program, supported by the SCAQMD, tested prototype water heaters capable of achieving NO_X emissions of less than about 0.02 lb/MMBtu.

CARB estimates the cost effectiveness of a 0.09-lb/MMBtu (output) NO_X limit for new natural gas water heaters to be $1600 per ton. The SCAQMD estimated the equipment and installation cost for retrofitting existing homes with one flat-plate solar collector at approximately $4000, making the cost effectiveness somewhat high ($300,000 to over $500,000 per ton of NO_X reduced). The cost effectiveness of using solar panels to heat water for new homes is about $62,500 per ton of NO_X reduced.

STATE AND LOCAL CONTROL EFFORTS

Several local California air quality districts including the SCAQMD, Ventura County Air Pollution Control District and the Santa Barbara County Air Pollution Control District have adopted regulations governing the permissible NO_X level of new water heaters and/or space heaters.

Natural-Gas-Fired Space Heaters. Regulations applicable to natural-gas-fired space heaters include SCAQMD Rule 1111, "NO_X Emissions from Natural-Gas-Fired, Fan-Type Central Furnaces," and Bay Area AQMD Regulation 9, Rule 4, "Nitrogen Oxides from Fan-Type Residential Central Furnaces." These rules apply to new space heaters rated up to 175,000 Btu/hr gross heat input duty. Both rules prohibit the sale, installation or offer for sale within the districts, of any stationary residential natural-gas-fired fan-type central furnace that emits more than 0.09 lb/MMBtu of NO_X, expressed as NO_2, of useful heat delivered to the heated space. SCAQMD Rule 1111 exempts furnaces that are to be installed in mobile homes.

Natural-Gas-Fired Water Heaters. Regulations applicable to residential water heaters include SCAQMD Rule 1121, "Control of Nitrogen Oxides from Residential Type, Natural-Gas-Fired Water Heaters," and BAAQMD Regulation 9, Rule 6, "Nitrogen Oxides Emissions from Natural-Gas-Fired Water Heaters — Control of NO_X". These rules apply only to new water heaters and prohibit the sale, or offer for sale within the districts, of gas-fired stationary home water heaters that emit nitrogen oxides (as NO_2) in excess of 0.09 lb/MMBtu of heat output. Exemptions from these rules include natural-gas-fired water heaters with a rated heat input of more than 75,000 Btu per hour and heaters used in recreational vehicles. The BAAQMD Rule 6 further exempts water heaters using a fuel other than natural gas, and natural gas-fired heaters used exclusively to heat swimming pools and hot tubs.

REFERENCES

1. U.S. Environmental Protection Agency. February 1992. *Summary of NO_X Control Technologies and Their Availability and Extent of Application.*

2. California Air Resources Board. August 7, 1992. *Sources and Control of Oxides of Nitrogen Emissions.*

3. SCAQMD. February 1992. Draft. *Federal Attainment Plan for Nitrogen Dioxide; Supplement to the 1991 Air Quality Management Plan.*

4. Alliance for Energy. 1993. *Industry Profile: The High Efficiency Gas Furnace Industry.*

5. Energy Information Administration. February 1993. *Household Energy Consumption, 1990.*

6. Energy Information Administration. February 1993. *Household Energy Consumption and Expenditures 1990; Supplement: Regional.*

Table 1

Geographic Distribution of Sources

	Gas Water Heaters		Gas Space Heaters		Oil Space Heaters	
	Households[1]	Consumption[2]	Households[1]	Consumption[2]	Households[1]	Consumption[2]
Northeast	9.6	239.8	8.9	715.6	7.8	649.6
Midwest	14.8	364.5	16.7	1,426.7	1.6	120.2
South	12.8	270.4	14.4	673.0	1.7	76.7
West	13.1	285.7	12.8	551.4	See note 3 below	See note 3 below

Source: Department of Energy.
[1]*Millions.*
[2]*Trillion Btu.*
[3]*Data not presented since source has limited use in that region.*

Table 2

Performance Summary of Low NO_x Control Equipment for Natural-Gas-Fired Residential Heaters

Control	Average Operating Excess Air (%)	Cyclic Pollutant Emissions (ng/J heat input)			Steady-State Efficiency (%)	Cycle Efficiency (%)	Comments
		NO_x[1]	CO	UHC[2]			
Conventional Unit	40-120	28-45	8.6-25	3.3-33	70	60-65	
Radiant Screen	40-120	15-18	6.4	*	75	70	Emissions of CO and HC can increase significantly if screen is not placed properly or deforms.
Secondary Air Baffle	60-80	22	14	*	*	*	Requires careful installation. Suited for single-port upshot burners.
Surface Combustion Burner	10	7.5	5.5-9.6	*	*	*	Not commercially available. Still under development.
Perforated Burner	*	7.7	26	*	85	80	Commercially available design.
Modulating Furnace	*	25	*	*	75	70	Furnace is essentially derated. Requires longer operation to deliver a given heat load.
Pulse Combustor	*	10-20	*	*	95	95	Being evaluated.
Catalytic Combustor	*	<5	*	*	90	85	Still at the R & D stage.

Source: EPA, February 1992.
[1]*Sum of NO + NO_2 reported as NO_2.*
[2]*Unburned hydrocarbons calculated as methane (CH_4).*
** = Not Available*

Table 3

Cost Effectiveness—Perforated Burner

Capacity or Size	Incremental Capital Investment ($)	Net Present Value of Operating Costs ($)	Lifetime NO_x Emission Reduction (tons)	Emission Control Method Cost Effectiveness ($/ton)
1,000,000 Btu/hr	High: 300 Low: 100	0	0.043	7100 to 2300

Source: Santa Barbara County Air Pollution Control District.

Table 4

Cost Effectiveness—Modulating Furnace

Capacity or Size	Incremental Capital Investment ($)	Net Present Value of Operating Costs ($)	Lifetime NO_x Emission Reduction (tons)	Emission Control Method Cost Effectiveness ($/ton)
1,000,000 Btu/hr	High: 250 Low: 50	0	0.043	5800 to 1200

Source: Santa Barbara County Air Pollution Control District.

Open Burning

Summary

Open burning can be conducted in drums, fields and open pits. Materials disposed of in this manner include municipal waste, agricultural waste, prescribed forest burning and landscape refuse. In general, the relatively low temperatures associated with open burning suppress NO_X emissions.

A number of jurisdictions control open burning by limiting the types of material that can be burned and the days, based on ambient conditions, on which materials may be burned. Open burning is controlled primarily for safety and nuisance considerations (e.g., particulate smoke). Very little work has been done to quantify the impact of open burning on NO_X emissions.

Description of Source

Open burning may occur in open drums or baskets, fields, yards and in large open dumps or pits. Materials commonly disposed of in this manner are municipal waste, auto body components, landscape refuse, agricultural field refuse, wood refuse, bulky industrial refuse and leaves. Range management burning and forest management burning are two additional sources of open burning.

Emissions Per Unit Output

Generally, the relatively low temperatures associated with open burning tend to increase particulates, CO and hydrocarbon emissions, while suppressing NO_X emissions. Ground-level open burning is affected by a number of variables, including wind, ambient temperatures, composition and moisture content of the debris burned and composition of the pile.

Given the relatively low level of NO_X emissions expected to result from open burning, little work has been done to quantify NO_X emissions. *Table 1* identifies the emission factors estimated by EPA for the open burning of selected materials.

National Emissions Estimate

According to EPA, total NO_X emissions from "government open burning dumps" are 7065 tons per year, while industrial open burning of wood, vegetation, leaves and general refuse produces 45 tons of NO_X per year.

Available Control Strategies

Open burning is controlled by limiting the types of materials that can be burned and the days on which open burning may occur. For example, California Health and Safety Code Regulations allow local air districts to declare a permissive burn day or a no-burn day, require that sources obtain a burn permit from the designated county or state agency, and limit burns to permissive burn days. Open burning is typically restricted to days with acceptable air quality, based largely on current and forecasted visibility and particulate levels.

Primarily as a VOC control strategy, EPA, in its proposed California FIP, expands the existing burn/no-burn program to incorporate ambient ozone air quality considerations. Specifically, open burning would be restricted to days when ambient ozone concentrations were within acceptable levels (i.e., at or below California's 0.09 ppm ozone standard). EPA believes the cost resulting from the lost opportunity to burn waste on the no-burns days would be minimized by allowing sources to burn on days when ozone exceedences are not predicted.

Another strategy to control NO_x emissions from open burning is to reduce the amount of refuse burned by recycling, in the case of municipal waste, or mulching, in the case of agricultural or landscaping waste.

Federal Rulemaking and/or Guidance Documents

EPA has proposed limits on open burning in the proposed California FIP. No other EPA rules or guidance documents exist.

State and Local Control Efforts

A number of states and localities have burn/no-burn days, primarily based on safety or visibility/particulate considerations. The Oregon air pollution control law applicable to open burning (ORS 468A.550 *et. seq.*, "Field Burning and Propane Flaming") is illustrative of this type of control. The Ventura County Air Pollution Control District currently restricts burning when the California ozone standard of 0.09 ppm is expected to be exceeded.

References

1. U.S. Environmental Protection Agency. September 1985. *Compilation of Air Pollutant Emission Factors, Volume I: Stationary, Point and Area Sources.*

2. U.S. Environmental Protection Agency. July 1993. *AIRS Facility Subsystem.*

STAPPA/ALAPCO *Recommendation*

▶ State and local agencies should consider restricting open burning for NO_X control purposes on days when the ozone standard is expected to be exceeded. Other opportunities to lower NO_X emissions include reducing the amount of refuse burned by recycling municipal waste or mulching agricultural or landscaping waste.

Table 1

NO_X Emission Factors for Uncontrolled Open Burning of Selected Materials

General Refuse	6.0 lb/ton burned
Vegetation/Wood/Leaves	4.0 lb/ton burned
Wood	4.0 lb/ton burned

Source: EPA.

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SECTION III

Mobile Sources

Mobile Sources

Introduction

This portion of the document assesses the potential NO_X emissions reductions that could be achieved through the implementation of different variations of mobile source control strategies. This analysis is based on the evaluation of mobile source control strategies addressed in STAPPA/ALAPCO's September 1993 *Meeting the 15-Percent Rate-of-Progress Requirement Under the Clean Air Act: A Menu of Options*. Where appropriate, that analysis has been updated. In conducting that analysis, a standard set of conditions was assumed for the vehicle fleet and its operations, including:

- the national vehicle mix;
- the national vehicle annual mileage distribution;
- the national vehicle age distribution;
- growth in vehicle miles traveled of 2.5 percent per year;
- Stage II vapor recovery in place by 1996 (77-percent effective for light-duty vehicles, 67-percent effective for heavy-duty vehicles);
- typical summer day conditions, with temperatures ranging from 68°F to 94°F;
- a good basic I/M program in effect by 1990 (assuming a program beginning in 1983, with annual testing of all 1968 and newer cars at test-only facilities, including an idle test at 20-percent stringency, with no waivers, and cutpoints for 1981 and newer cars of 220 parts per million HC and 1.2 percent carbon monoxide);
- American Society for Testing and Materials (ASTM) area Class C;
- average speed of 33 miles per hour; and
- total mileage of 1 million miles per day in 1990.

With respect to motor vehicle Inspection and Maintenance, reformulated gasoline and California low-emission vehicles, two overall scenarios were considered for each: one excluding nonroad vehicles and engines and one including them. Both of these scenarios were considered because nonroad vehicles and engines represent a very important source of NO_X emissions in many areas. According to EPA, on a typical summer day, nonroad vehicles and engines are responsible on a nationwide basis for 34 percent of the total motor vehicle and engine NO_X emissions.

Although there are substantial efforts currently underway both on the federal level and in California to regulate new nonroad vehicles and engines, it is unlikely that these efforts will result in any emissions impact prior to 1996, other than those associated with fuel reformulation. Therefore, for the scenarios including nonroad vehicles, it was assumed that such sources would increase at a rate of 1 percent per year and that they would be uncontrolled, except where states take action.

Importantly, the sequence with which these strategies are introduced can have a vital impact on the emissions reduction achieved. In addition, each individual element of the strategies may not be additive. For example, the benefits of reformulated gasoline in an area with an enhanced motor vehicle Inspection and Maintenance program will not be the same as the benefits that will result in an area without an enhanced Inspection and Maintenance program.

The information related to mobile source control strategies included in this section should be used by state and local air quality agencies to determine which programs to consider in developing strategies to reduce motor vehicle NO_X emissions. However, it is not intended to be a substitute for a thorough state or local agency analysis using MOBILE5a, applicable EPA guidance documents and other available information, in that actual State Implementation Plan credits will vary depending upon local conditions. Although the benefits identified for the programs addressed in this document provide an accurate illustration of the contributions such programs can make to an air pollution control strategy, EPA cannot verify that these benefits reflect the actual SIP credits that will result under a specific set of circumstances.

Motor Vehicle Inspection and Maintenance

DESCRIPTION OF CONTROL MEASURE

Due to poor maintenance, deliberate tampering with or removal of pollution controls (particularly catalysts) and misfueling (i.e., using leaded fuel in vehicles that require unleaded fuel), motor vehicles in use have consistently emitted pollutants well in excess of the established standards. Motor vehicle Inspection and Maintenance (I/M) programs have been singled out as the primary means to rectify these problems by identifying vehicles in need of remedial maintenance or adjustment and, accordingly, requiring appropriate repairs. I/M programs are intended to encourage vehicle owners to keep their cars in a good state of repair, the service industry to conduct maintenance properly and manufacturers to make vehicles more durable and serviceable.

While I/M programs have been required by the federal Clean Air Act since 1977, details of program implementation have generally been left to the discretion of state and local officials, with broad policy guidelines from EPA. With adoption of the Clean Air Act Amendments of 1990 (CAAA), this approach changed. Both the House and Senate made "enhanced" I/M a cornerstone of their clean air bills. The I/M provisions of the House bill, which were ultimately adopted in Conference, were especially strong. They required annual, test-only programs, or programs that achieve equivalent reductions, in more seriously polluted areas. In addition, a minimum repair cost waiver of $450 was established and, for the first time, NO_X testing was required in ozone nonattainment areas.

Pursuant to the CAAA, Moderate ozone nonattainment areas, as well as Marginal ozone nonattainment areas previously required to have an I/M program, must implement "basic" I/M requirements. "Enhanced" I/M programs are required in Serious, Severe and Extreme ozone nonattainment areas with urbanized populations of 200,000 or more. In addition, carbon monoxide (CO) nonattainment areas with a design value exceeding 12.7 parts per million (ppm) and with an urbanized population of 200,000 or more, as well as all Metropolitan Statistical Areas with a population of 100,000 or more in the northeast Ozone Transport Region, must also implement enhanced I/M.

For the purposes of implementing the statutory I/M provisions, EPA has constructed a model program, based upon a performance standard within which areas have flexibility to design their own particular I/M programs.

An area is essentially required to determine the emissions reductions that would be achieved by the model program when applied to the affected vehicle fleet using the most current version of the mobile source emissions model. The area must demonstrate, using the same model, that its program will achieve the same or greater emissions reductions. An area's air quality status will determine which performance standard(s) (ozone, CO or both) apply.

Basic I/M Performance Standard. Areas required to implement a basic I/M program must achieve at least as great a reduction in emissions as a model program that includes the following elements:

- test only;
- a start date of 1983 for existing areas and 1994 for newly-required programs;
- annual testing;
- applicability to all 1968 and later model year light-duty vehicles;
- an idle test;
- no emissions control device inspections;
- a 20-percent emissions test failure rate among pre-1981 model year vehicles;
- a $75 repair cost waiver for pre-1981 vehicles and a $200 repair cost waiver for 1981 and later model year vehicles;
- a 0-percent waiver rate;
- a 100-percent compliance rate;
- testing of the vehicle's onboard diagnostic (OBD) system (applicable to vehicles certified to comply with OBD regulations; EPA will be establishing specific requirements, now that a final OBD regulation has been promulgated); and
- emissions standards no weaker than specified in 40 CFR, Part 85, Subpart W.

Basic I/M programs must be shown to achieve the same or lower emissions levels as the model inputs by 1997 for ozone nonattainment areas and by 1996 for CO nonattainment areas. As noted earlier, this basic I/M program was assumed to apply in the 1990 base case.

Enhanced I/M Performance Standard. To comply with the enhanced I/M requirements of the CAAA, EPA has defined a model program that includes the following elements:

- test only;
- a start date of in 1983 for existing areas or 1994 for newly subject areas;
- annual testing;
- applicability to all 1968 and later model year light-duty vehicles and light-duty trucks rated up to 8500 pounds Gross Vehicle Weight Rating (GVWR);
- transient mass emission testing on 1986 and later model year vehicles using the IM240 driving cycle, two-speed testing of 1981-1985 vehicles and idle testing of pre-1981 vehicles;
- maximum exhaust dilution measured as no less than 6 percent CO plus carbon dioxide (CO_2) on vehicles subject to a steady-state test;
- visual inspection of the catalyst and fuel inlet restrictor on all 1984 and later model year vehicles;
- an evaporative system integrity (pressure) test on 1983 and later model year vehicles and an evaporative system transient purge test on 1986 and later model year vehicles;
- a 20-percent emission test failure rate among pre-1981 model year vehicles;
- a $75 repair cost waiver for pre-1981 vehicles, and a $200 repair test waiver for 1981 and later model year vehicles;
- a $450 repair cost waiver;
- a 3-percent waiver rate as a percentage of failed vehicles;
- a 96-percent compliance rate;
- on-road testing of 0.5 percent of the subject vehicle population (as a supplement to the periodic inspection), to measure annually hydrocarbons (HC), CO, NO_x and/or CO_2 emissions on any road or roadside in the nonattainment area or the I/M program area;
- testing of the vehicle's OBD system (applicable to vehicles certified to comply with OBD regulations; EPA will be establishing specific requirements, now that a final OBD regulation has been promulgated); and
- emissions standards as follow:
  - for 1986 through 1993 model year light-duty vehicles and 1994 and 1995 light-duty vehicles not meeting Tier I standards, emissions standards of 0.80 grams per mile (gpm) HC, 20 gpm CO and 2.0 gpm NO_x apply;
  - for 1986 through 1993 model year light-duty trucks less than 6000 pounds GVWR and 1994 and 1995 light-duty trucks not meeting Tier I standards, emissions standards of 0.80 gpm HC, 15 gpm CO and 2.5 gpm NO_x apply;
  - for 1986 through 1993 model year light-duty trucks greater than 6000 pounds GVWR and 1994 and 1995 light-duty trucks not meeting Tier I standards, emissions standards of 0.80 gpm HC, 15 gpm CO and 3.0 gpm NO_x apply;
  - for 1994 and later light-duty vehicles meeting

Tier I standards, emissions standards of 0.70 gpm non-methane hydrocarbons (NMHC), 15 gpm CO and 1.4 gpm NO_X apply;
- for 1994 and later light-duty trucks under 6000 pounds GVWR and meeting Tier I standards, emissions standards of 0.70 gpm NMHC, 15 gpm CO and 2.0 gpm NO_X apply;
- for 1994 and later light-duty trucks greater than 6000 pounds GVWR and meeting Tier I standards, emissions standards of 0.80 gpm NMHC, 15 gpm CO and 2.5 gpm NO_X apply; and
- for 1981 through 1985 model year vehicles, standards of 1.2 percent CO and 220 ppm HC for the idle, two-speed tests and loaded steady-state tests apply.

Enhanced I/M programs must be shown to obtain the same or lower emissions levels as the model inputs by 2000 for ozone nonattainment areas and 2001 for CO nonattainment areas. In Severe and Extreme ozone nonattainment areas, such a demonstration must also be made on each applicable milestone and attainment deadline thereafter; milestones for NO_X must be the same as those for ozone.

Available Control Strategies

NO_X reductions achieved by an enhanced I/M program, over and above those that would be achieved by a basic I/M program, are creditable toward the post-1996 3-percent per year VOC reduction requirement under EPA's NO_X Substitution Guidance.

EPA has developed a model program to define the enhanced I/M performance standard. Although this performance standard is based upon an annual program, areas have the option of adopting a biennial program that achieves equivalent emissions benefits by 1999.

Areas that wish to achieve higher levels of emissions reductions from their enhanced I/M programs in order to meet their 1996 and subsequent-year reasonable further progress targets can do so by, among other things, increasing the model year coverage, increasing the vehicle class coverage, increasing the pre-1981 stringency rate or adopting an annual program. Tighter cutpoints would be another option.

To illustrate the potential benefits of programs that go beyond the minimum requirements, two alternative programs were modeled. In the first scenario — called "maximum coverage" I/M — the vehicle population subject to I/M is expanded to include all categories of gasoline-fueled vehicles. In addition, IM240 and purge and pressure tests are used for all 1975 and newer vehicles.

STAPPA/ALAPCO
Recommendation

▶ Areas not now required to implement IM240 should consider adopting this program in order to control NO_X, since IM240 specifically tests for NO_X and requires repairs accordingly. Additional NO_X reductions can be achieved by expanding the geographic coverage of the program, increasing the model year coverage, increasing the vehicle class coverage, increasing the pre-1981 stringency rate, conducting inspections on an annual basis and/or setting tighter cutpoints.

In the second scenario — called "maximum overall" I/M — in addition to broader vehicle coverage, all inspected vehicles are subject to anti-tampering inspection of all components. Other variations are, of course, possible, but the options addressed here provide an indication of the additional emissions reduction potential of adopting a more aggressive I/M program than required by EPA.

Potential National Emissions Reduction

Figures 1 and 2 summarize the NO_X emissions reduction potential of enhanced I/M, "maximum coverage" I/M and "maximum overall" I/M. As depicted, I/M programs can result in significant NO_X reductions from the adjusted 1990 baseline. It is important to note that, although overall NO_X emissions will decrease from actual 1990 levels by 1996, when compared to the adjusted 1990 baseline, NO_X emissions from mobile sources in 1996 will, in fact, increase as a result of the assumed 2.5-percent annual growth in vehicle miles traveled. Therefore, with an I/M program in place, the net increase in NO_X emissions for model year 1996 will be lower than if there were no I/M program in place.

Figure 2 illustrates the impact of I/M on overall motor vehicle emissions, including uncontrolled and growing nonroad emissions. Not surprisingly, the overall percentage benefits decline. (Please note, however, that these estimates do not apply I/M to nonroad vehicles and engines but, rather, show the relative impact of I/M programs for highway vehicles on overall motor vehicle emissions, including those from nonroad sources. The section on nonroad vehicles and engines provides information on the control of this source category.)

Costs and Cost Effectiveness

EPA has estimated the inspection cost of the model enhanced I/M program to be $17 per vehicle in an effectively run, high-volume program. If the inspection were performed biennially, the estimated annual per vehicle cost would be approximately $9.

EPA has estimated the cost effectiveness of a biennial I/M program to be approximately $500 per ton of VOC. No comparable number was provided for NO_x emissions.

Federal Rulemaking and/or Guidance Documents

On November 5, 1992, EPA published a final I/M rule (57 *Federal Register* 52950). In addition, the agency has issued a number of guidance documents related to I/M (see *References* section).

State and Local Control Efforts

Table 1 identifies all the areas and states required to implement basic and enhanced I/M programs. Practically all of these affected areas have secured legislative authority to implement the required programs. Those areas that have opted or are considering opting into the enhanced I/M program where only basic I/M is required include Arizona, Ohio, Missouri and Michigan. Because only basic I/M is required in these states, EPA permits the states' selected enhanced I/M program design components to vary slightly from EPA's model enhanced I/M program, although the same overall emissions reductions are required. Most significantly, these states' programs most likely will have cost waivers lower than the $450 required for enhanced I/M programs, and they may choose to implement less stringent quality control measures.

In addition, California has recently negotiated an agreement with EPA for an I/M program that allows for hybrid centralized and decentralized testing. This program was designed specifically to address California's unique concerns and infrastructure. California is required to conduct an extensive study to be completed by December 31, 1994, after which EPA has 45 days to analyze the data and make a determination of equivalency to its enhanced I/M performance standards.

References

1. U.S. Environmental Protection Agency, Office of Mobile Sources. November 5, 1992. *Inspection/Maintenance Program Requirements*. Final Rule (57 *Federal Register* 52950).

2. U.S. Environmental Protection Agency, Office of Mobile Sources. March 1993. *MOBILE5 User's Guide*. Draft.

3. U.S. Environmental Protection Agency, Office of Mobile Sources. November 1992. *I/M Costs, Benefits, and Impacts*.

4. U.S. Environmental Protection Agency, Office of Mobile Sources. July 1993. *High Tech I/M Test Procedures, Emission Standards, Quality Control Requirements, and Emission Specifications*. Revised Technical Guidance.

5. U.S. Environmental Protection Agency, Office of Mobile Sources. May 1993. *Evaluation of a Four-Mode Steady-State Test With Acceleration Simulation Mode As An Alternative Inspection And Maintenance Test For Enhanced I/M Programs*.

6. U.S. Environmental Protection Agency, Office of Mobile Sources. March 24, 1993. *Supplemental Guidance for I/M Programs: Vehicle Repair, Technician Training and Certification, and Repair Shop Tracking*. Draft.

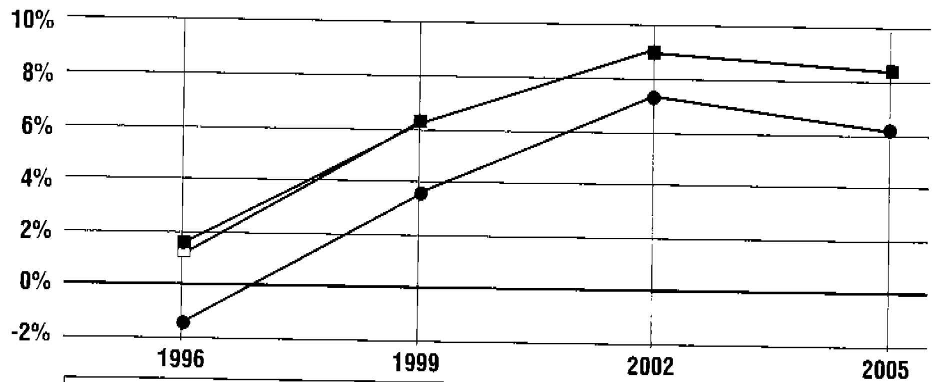
7. Memorandum of Agreement Between the California Environmental Protection Agency and the U.S. Environmental Protection Agency. March 21, 1994.

Figure 1

Impact of I/M Options on NO_x Emissions

Percent Reduction From Adjusted 1990 Baseline — Highway Vehicles Only

● Enhanced
□ Maximum Coverage
■ Maximum Overall



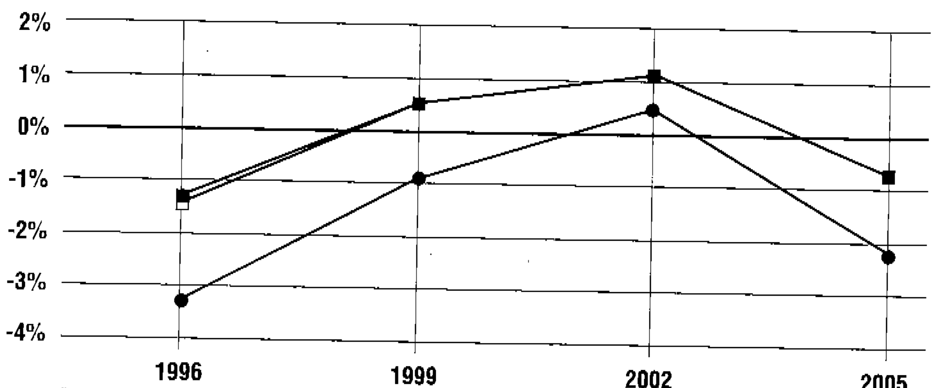
	1996	1999	2002	2005
Enhanced	-1.47%	3.90%	7.54%	6.09%
Maximum Coverage	1.24%	6.34%	9.11%	8.35%
Maximum Overall	1.70%	6.34%	9.11%	8.35%

Figure 2

Impact of I/M Options on NO_x Emissions

Percent Reduction From Adjusted 1990 Baseline — Highway and Nonroad Vehicles

● Enhanced
□ Maximum Coverage
■ Maximum Overall



	1996	1999	2002	2005
Enhanced	-3.20%	-1.01%	0.05%	-2.12%
Maximum Coverage	-1.49%	0.52%	1.05%	-0.70%
Maximum Overall	-1.21%	0.52%	1.05%	-0.70%

Table 1

List of Enhanced and Basic I/M Areas

INSPECTION/MAINTENANCE FACTS AND FIGURES

	Currently Operating	Not Operating	Total
Affected States	35	3	38
Basic Urban Areas	75	24	99
Enhanced Areas			
Urbanized Areas	17	1	18
Metropolitan Statistical Areas	37	28	65
Enhanced Subtotal	54	29	83
Total Cities (MSAs & Urban Areas)	131	51	182

ENHANCED I/M AREAS*

Currently Operating**

Allentown-Bethlehem, PA-NJ MSA
Atlanta, GA
Atlantic City, NJ MSA
Bakersfield, CA
Baltimore, MD MSA
Baton Rouge, LA
Bergen-Passaic, NJ PMSA
Boston, MA PMSA
Bridgeport-Milford, CT PMSA
Brockton, MA PMSA
Chicago, IL-NW Indiana
Danbury, CT PMSA
Denver, CO
El Paso, TX-NM
Fall River, MA-RI PMSA
Fitchburg-Leominster, MA MSA
Fresno, CA
Hartford, CT PMSA
Houston, TX
Jersey City, NJ PMSA
Las Vegas, NV
Lawrence-Haverhill, MA-NH PMSA
Los Angeles, CA
Lowell, MA-NH PMSA
Middlesex-Somerset-Hunterdon, NJ PMSA
Milwaukee, WI
Monmouth-Ocean, NJ PMSA
Nashua, NH PMSA
Nassau-Suffolk, NY PMSA
Newark, NJ PMSA
New Bedford, MA MSA
New Britain, CT PMSA
New Haven-Meriden, CT MSA
New London-Norwich, CT-RI MSA
New York, NY PMSA
Norwalk, CT PMSA
Oxnard-Ventura, CA
Philadelphia, PA-NJ PMSA
Pittsburgh, PA PMSA
Pawtucket-Woonsocket-Attleboro, RI-MA PMSA
Riverside-San Bernadino, CA
Sacramento, CA
Salem-Gloucester, MA MSA
San Diego, CA
Seattle, WA
Spokane, WA
Springfield, MA MSA
Stamford, CT PMSA
Trenton, NJ PMSA
Vineland-Millville-Bridgeton, NJ PMSA
Washington, DC-MD-VA MSA
Waterbury, CT MSA
Wilmington, DE-NJ-MD PMSA
Worcester, MA MSA

Not Operating

Albany-Schenectady-Troy, NY MSA
Altoona, PA MSA
Binghamton, NY MSA
Buffalo, NY PMSA
Burlington, VT MSA
Erie, PA MSA
Glen Falls, NY MSA
Hagerstown, MD MSA
Harrisburg-Lebanon-Carlisle, PA MSA
Jamestown-Dunkirk, NY MSA
Johnstown, PA MSA
Lancaster, PA MSA
Manchester, NH MSA
Niagara Falls, NY PMSA
Orange County, NY PMSA
Portland, ME MSA
Portsmouth-Dover Rochester, NH-ME MSA
Poughkeepsie, NY MSA
Providence, RI PMSA
Reading, PA MSA
Rochester, NY MSA
Scranton-Wilkes Barre, PA MSA
Sharon, PA MSA
State College, PA MSA
Syracuse, NY MSA
Tacoma, WA
Utica-Rome, NY MSA
Williamsport, PA MSA
York, PA MSA

Table 1 (Cont.)

List of Enhanced and Basic I/M Areas

BASIC I/M AREAS*

Currently Operating**

Albuquerque, NM	Hemet-San Jacinto, CA	Racine, WI
Alton, IL	Hesperia-Apple Valley-Victorville, CA	Raleigh, NC
Anchorage, AK	High Point, NC	Reno, NV
Antioch-Pittsburg, CA	Indio-Coachella, CA	Round Lake Beach-McHenry, IL-WI
Aurora, IL	Jacksonville, FL	Salinas, CA
Boise, ID	Joliet, IL	Salt Lake City, UT
Boulder, CO	Kenosha, WI	San Francisco-Oakland, CA
Bristol, CT	Lancaster-Palmdale, CA	San Jose, CA
Charlotte, NC	Lodi, CA	San Luis Obispo, CA
Cincinnati, OH-KY	Lompoc, CA	Santa Barbara, CA
Chico, CA	Lorain-Elyria, OH	Santa Cruz, CA
Cleveland, OH	Louisville, KY-IN	Santa Maria, CA
Colorado Springs, CO	Medford, OR	Santa Rosa, CA
Dallas-Ft. Worth, TX	Memphis, TN-AR-MS	Seaside-Monterey, CA
Davis, CA	Merced, CA	Simi Valley, CA
Detroit, MI	Miami-Hialeah, FL	St. Louis, MO-IL
Durham, NC	Middletown, OH	Stockton, CA
Elgin, IL	Minneapolis-St. Paul, MN	Tampa-St. Petersburg-Clearwater, FL
Fairbanks, AK	Modesto, CA	Tucson, AZ
Fairfield, CA	Napa, CA	Vacaville, CA
Fort Collins, CO	Nashville, TN	Visalia, CA
Fort Lauderdale-Hollywood-Pompano, Beach, FL	Ogden, UT	West Palm Beach-Boca Raton-Delray Beach, FL
Gastonia, NC	Palm Springs, CA	Winston Salem, NC
Greeley, CO	Phoenix, AZ	
Greensboro, NC	Portland-Vancouver, OR-WA	
Hamilton, OH	Provo-Orem, UT	

Not Operating

Akron, OH	Grand Rapids, MI	Petersburg-Colonial Heights, VA
Ann Arbor, MI	Holland, MI	Port-Arthur, TX
Beaumont, TX	Huntington-Ashland, WV-KY-OH	Port Huron, MI
Charleston, WV	Lewiston-Auburn, ME	Richmond, VA
Crystal Lake, IL	Lewisville, TX	Sheboygan, WI
Dayton, OH	Muskegon, MI	Springfield, OH
Denton, TX	Newport, RI	Texas City, TX
Galveston, TX	Parkersburg, WV-OH	Toledo, OH-MI

* *This list shows Metropolitan Statistical Areas (MSAs) and Primary Metropolitan Statistical Areas (PMSAs) in the northeastern Ozone Transport Region and urbanized areas in the rest of the country.*

** *These areas are currently operating I/M programs but are not necessarily meeting enhanced I/M requirements.*

Source: EPA, July 15, 1993.

Reformulated Gasoline and Diesel Fuels

Description of Control Measure

Federal Reformulated Gasoline. The Clean Air Act Amendments of 1990 require significant changes to conventional fuels. For areas that exceed the health-based ozone standard, the CAAA require EPA to establish specifications for reformulated gasoline that would achieve the "greatest reduction" of ozone-forming VOCs and toxic air pollutants achievable, considering costs and technological feasibility.

Beginning on January 1, 1995, this cleaner, "reformulated" gasoline must be sold in areas of the country with the worst nonattainment problems and populations over 250,000. Accordingly, use of reformulated gasoline is mandated, beginning in 1995, in nine areas—Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York, Philadelphia and San Diego. Other ozone nonattainment areas are permitted to "opt-in" to the federal reformulated gasoline program, provided sufficient quantities of fuel can be made available.

At a minimum, reformulated gasoline must 1) not cause an increase in NO_X emissions (if necessary, EPA may modify other requirements discussed below to prevent such an increase), 2) have an oxygen content of at least 2.0 percent by weight (EPA may waive this requirement if it would interfere with attaining an air quality standard), 3) have a benzene content no greater than 1.0 percent by volume and 4) contain no heavy metals, including lead or manganese (EPA may waive the prohibition against heavy metals other than lead if it is determined that the metal will not increase, on an aggregate mass or cancer-risk basis, toxic air emissions from motor vehicles).

The CAAA require that, beginning in 1995, reformulated gasoline result in summertime emissions of VOCs and year-round emissions of air toxics that are 15 percent lower than those that would occur from the use of normal "baseline" gasoline; by the year 2000, these emissions must be 25 percent lower. EPA may adjust the 25-percent requirement up or down based upon technological feasibility and cost considerations, but in no event may the percent reduction beginning in the year 2000 be less than 20 percent. Toxic air pollutants are defined by the CAAA in terms of the aggregate emissions of benzene, 1,3 butadiene, polycyclic organic matter, acetaldehyde and formaldehyde.

One concern raised during the Congressional debate was that toxic or other harmful compounds removed from gasoline in polluted areas would be "dumped" into gasoline in other parts of the country. To prevent this, EPA was required to establish regulations prohibiting the introduction into commerce of gasoline that, on average, results in emissions of VOC, NO_X or toxics greater than gasoline sold by that refiner, blender or importer in 1990. These regulations were mandated to take effect by January 1, 1995.

On February 16, 1994 (59 *Federal Register* 7716), EPA published final regulations implementing the CAAA mandate on reformulated gasoline. The rule was developed in major part through a regulatory negotiation with interested parties, including state and local air quality officials, the oil and automobile industries, oxygenate suppliers, gasoline retailers, environmental organizations and others.

As required, the regulations establish Phase I and Phase II reformulated gasoline requirements, as well as anti-dumping prohibitions. For Phase I, during the period 1995-1997, refiners may use a "simple model" to certify that a gasoline meets applicable emissions reduction standards. For 1998-1999, a "complex model" would replace the simple model. Following is a discussion of EPA's regulations as they relate primarily to impacts on NO_X.

Phase I Federal Reformulated Gasoline Simple Model. The simple model for VOC emissions is comprised of fuel specifications for RVP and oxygen. Fuels sold at retail outlets must have an RVP during the EPA-defined "high-ozone season" (June 1 through September 15) of no more than 7.2 psi in VOC control region 1 (the southern areas typically covered by ASTM class B during the summer) and 8.1 psi in VOC control region 2 (the northern areas typically covered by ASTM class C during the summer). The differences in climate between these two types of areas require a corresponding difference in gasoline volatility to achieve the same emissions effect. The period of June 1 through September 15 was chosen for the high-ozone season because most ozone violations occur during this period.

The Clean Air Act requires that there be no NO_X emissions increase resulting from reformulated gasoline. In the early stages of the rule development, available data suggested that fuel oxygen content and the types of oxygenate used could have an impact on NO_X emissions. When additional data became available, however, EPA concluded that there did not appear to be any significant difference between the NO_X emissions effects of oxygen from different oxygenates.

Under the complex model, discussed below, oxygen has been found to result in no NO_X increase. In fact, it results in a very slight decrease. However, the other changes in fuel properties that occur when oxygenates are added both increase and decrease NO_X emissions. As a result, EPA concluded that there is no assurance under the simple model that the addition of an oxygenate will not increase NO_X emissions. For that reason, EPA decided that it was still appropriate to cap the maximum oxygenate content under the simple model at 2.7 percent by weight.

> **STAPPA/ALAPCO**
> ***Recommendation***
>
> ▶ Areas not already required by the Clean Air Act to implement the federal reformulated gasoline program should seriously consider opting into the program. In addition to achieving substantial reductions in emissions of VOCs and toxics, the reformulated gasoline program also offers relatively significant NO_X reductions beginning in the year 2000. Alternatively, states can exercise the provisions of Section 211(c)(4) of the Act and adopt their own reformulated gasoline program, including the California reformulated gasoline program or one focused exclusively on fuel properties (e.g., reducing the sulfur content of the fuel) affecting NO_X emissions. States can also adopt reformulated diesel fuel requirements, including the California reformulated diesel program, which may yield additional NO_X reductions from diesel engines.

Phase I Complex Model. The complex model evaluates the emissions impact of a number of fuel properties over a possible range of parameter values (see *Table 1*) using a series of equations (two for each pollutant).

Phase I reformulated gasoline certified by the complex model must meet the performance standards for 1998-1999, relative to the Clean Air Act baseline gasoline established by EPA (see *Table 2*). The NO_X performance standard under the complex model during Phase I must satisfy the no-NO_X-increase requirement on a per-gallon basis, or meet a 1.5-percent reduction for compliance on average. Emissions testing of reformulated fuel is permitted to augment the use of the complex model, but testing alone cannot be used to certify fuel.

Phase II Reformulated Gasoline for 2000 and Later. EPA established a per-gallon Phase II VOC performance standard of a 25.9-percent reduction in emissions for VOC control region 2 (northern areas) and a 27.5-percent reduction for VOC control region 1 (southern areas). EPA also established a per-gallon toxic performance standard of 20 percent for all reformulated gasoline. Finally, EPA required that Phase II reformulated gasoline will have to meet a 5.5-percent-per-gallon reduction in NO_x emissions. For refiners electing to utilize the averaging provisions, the performance standards differ somewhat (see *Table 3*).

The CAAA requires only that there be no net increase in NO_x emissions resulting from the use of reformulated gasoline. EPA, however, decided to exercise its discretion to require reductions in NO_x emissions. The agency cited the fact that gasoline vehicles contributed 20-35 percent of the total urban NO_x inventories in 1990 and are expected to contribute similar amounts in 2000.

California Reformulated Gasoline. On September 18, 1992, the California Air Resources Board (CARB) adopted regulations for its Phase II reformulated gasoline program. These regulations establish a comprehensive set of gasoline specifications designed to achieve maximum reductions in emissions of VOCs, NO_x, CO, sulfur dioxide and toxic air pollutants from gasoline-fueled vehicles. CARB has stated that the primary purpose of its Phase II gasoline reformulation is to reduce pollutant emissions from the existing fleet of pre-low-emission vehicles.

The California Phase II reformulated gasoline regulations establish standards for eight gasoline characteristics — sulfur, benzene, olefin, aromatic hydrocarbons, oxygen, RVP, T-90 and T-50 — applicable starting March 1, 1996. The regulations also provide for the certification of alternative gasoline formulations based on vehicle emissions testing.

The standards for the six properties other than RVP and oxygen content are set in two tiers; each property has an absolute limit, or "cap," that will apply to all gasoline (including alternative formulations) throughout the distribution system, and a more stringent standard that will apply to gasoline as it is supplied by the refiner or importer. A refiner or importer will have two options for each of the more stringent standards. It may meet a "flat" limit, not to be exceeded by any batch of gasoline, or it can meet a lower limit on average for many batches, as long as no batch exceeds the cap (see *Table 4*).

Through testing or modeling, a refiner may establish an alternative set of fleet or averaging standards (but not caps) under which to produce gasoline. Such alternative standards must be demonstrated to not cause emissions greater than those attributable to the basic standards.

CARB estimates the NO_x reduction from Phase II California reformulated gasoline to be 6 percent, compared to motor vehicles using California Phase I gasoline.

On April 22, 1994, CARB staff proposed amending the California Phase II reformulated gasoline requirements to allow the sale of gasoline meeting alternative gasoline specifications identified through the application of a predictive model. The staff report accompanying the proposal stated that the changes would not adversely affect the emissions reduction benefits of the Phase II reformulated gasoline rule.

Reformulated Diesel Fuel. On August 21, 1990, (55 *Federal Register* 34120) EPA promulgated its low-sulfur diesel rulemaking. On May 7, 1992 (57 *Federal Register* 19535) EPA amended its rule to comply with Section 211(i) of the CAAA of 1990. CARB adopted its clean diesel fuel regulations in November 1988 and on December 26, 1991, enacted the clean diesel fuel program. Both the EPA and CARB programs became effective on October 1, 1993. The two programs are similar and both are designed to substantially reduce sulfate and particulate and to allow manufacturers to comply with 1994 and newer emissions standards for diesel vehicles. Several important differences, however, exist between the EPA and CARB programs, as outlined below.

The EPA program applies only to diesel fuel for use in on-highway vehicles. Trucks, automobiles and buses are affected, for example, but construction and farm equipment are not, unless they choose to use low-sulfur diesel fuel. The regulation sets a 0.05-percent-by-weight sulfur limit for all on-road diesel fuel and requires a minimum cetane index of 40 or maximum 35-percent-by-volume aromatics percentage. Since direct measurement of aromatics is a somewhat complicated procedure, EPA chose to use a minimum cetane index as a surrogate for capping aromatics. Few refiners have had trouble meeting this requirement and those who cannot can sell fuel into the nonroad market. EPA estimated the price differential between high-sulfur and low-sulfur fuels to be approximately 2¢/gallon, once initial distribution "blips" have resolved themselves.

The California program applies to vehicular diesel fuel. Essentially, any vehicle with wheels, including construction and farm equipment, is covered. The regulation establishes a 0.05-percent-by-weight sulfur limit, as well as a 10-percent cap on aromatics (20 percent for small refiners). Diesel fuel normally has about 30 percent aromatics. California and EPA believe aromatics contribute to the formation of NO_x and particulate emissions. California includes an equivalency provision that allows refiners to make a diesel fuel with more than 10 percent aromatics if engine testing demonstrates equivalent emissions.

Most, if not all, of the large California refiners are pursuing higher-aromatic equivalent fuels. While a few oil companies have received CARB certification for their equivalent fuels, only Chevron has gone public with its formulation at this time. One of Chevron's alternatives has 19 percent aromatics, with 200 ppm sulfur and a cetane number of 59. According to EPA, Chevron estimates that it can manufacture this fuel at an incremental cost of 6-7 cents per gallon. EPA estimates this to be about half the incremental cost to make a strict 10-percent-aromatics fuel. California has granted temporary waivers from the requirements, provided the refiner pays 6¢/gallon into a trust fund. California's rule is expected to achieve NO_x emissions reductions that will not be achieved by the federal program. CARB estimates these reductions will be approximately 4-7 percent of diesel engine NO_x.

Available Control Strategies

Gasoline Fuel. States and localities have several options with respect to conventional fuels. First, as noted above, they can opt into the federal reformulated gasoline program. Alternatively, they can exercise the provisions of Section 211(c)(4) of the CAAA and adopt their own reformulated gasoline program. Under this option, a state could adopt the California reformulated gasoline requirements or could choose to focus solely on those fuel properties that affect NO_x emissions. As discussed below, EPA has found that the fuel parameter with the greatest impact on NO_x emissions is the sulfur content — reducing the sulfur content of gasoline reduces NO_x emissions.

For example, EPA estimates the incremental cost of reducing sulfur to 100 ppm, which EPA calculates would result in an 8.7-percent reduction in NO_x emissions, would be $0.52 per gallon or $6200 per ton of NO_x removed. These cost estimates are based on regionwide implementation; if the requirement was imposed state-by-state, the cost could be considerably higher.

State adoption of "custom gasoline" is not an easy process. The need must be clearly shown or EPA will withhold approval. Further, requiring non-federal gasoline creates additional enforcement burdens on the state or local implementing agency.

Diesel Fuel. States could opt to adopt California reformulated diesel fuel and further require its use by non-highway vehicles. Issues that must be considered in evaluating such a strategy are fuel availability, costs (in California fuel costs in some instances increased by more than 20 cents per gallon) and impact on possible injector pump seals (a limited number of engines operating on California reformulated diesel fuel experienced fuel leaks and other problems).

Potential National Emissions Reduction

No NO_x emissions reduction from the federal reformulated gasoline regulation is expected before the year 2000. With Phase II reformulated gasoline, beginning in 2000, EPA requires a NO_x emissions reduction standard of 6.8 percent on average. The agency projects that this requirement will result in an approximately 22,000-ton reduction in NO_x emissions in the nine cities required to implement the reformulated gas program, as well as those that have already opted into the program (incremental to Phase I).

MOBILE5a models federal reformulated gasoline in accordance with EPA's proposal of February 26, 1993, which does not require any improvement in NO_x emissions. EPA's final rule, published on February 16, 1994, will require a 6.8-percent NO_x reduction. EPA intends to modify MOBILE5a to account for this additional reduction, but it has not yet done so. Therefore, the reductions calculated by MOBILE5a tend to understate the NO_x benefits from federal reformulated gasoline after the year 2000. Since the 6.8-percent reduction only applies to gasoline-fueled vehicles and will likely achieve its full benefit only on 1986 and newer model year light-duty vehicles, the overall incremental impact will be substantially below 6.8 percent.

CARB estimates that NO_x reductions statewide from Phase II reformulated gasoline will be 50 tons per day in 1996 and 40 tons per day in the year 2000.

Costs and Cost Effectiveness

It is difficult to estimate the costs and the cost effectiveness of federal fuel modifications because the requirements are usually written in terms of a performance outcome that can be achieved in many different ways. In addition, refiners differ widely in terms of the characteristics of the fuels they produce.

The methodology used by EPA for determining the cost effectiveness of fuel component changes is described in EPA's RFG rule Regulatory Impact Analysis. Individual fuel component control costs and the effects of changes in one fuel component on the other fuel components are integral factors in the determination of the cost effectiveness. EPA concluded that sulfur is the only fuel parameter that results in significant NO_x reductions at a reasonable cost (see *Table 5*). Changes in other fuel parameters have only a small effect on NO_x emissions at significantly higher costs, with the possible exception of olefin control (which would increase VOC at the same time it reduced NO_X).

According to EPA, a NO_X reduction of approximately 6.8 percent could be achieved with sulfur control down to approximately 138 ppm at a reasonable cost — about $3200 per ton of NO_X removed — whether compared on the basis of the cost of the last increment of reduction (5.8 percent to 6.8 percent NO_X) or the overall cost incremental to Phase I reformulated gasoline.

The cost effectiveness of a 6.8-percent NO_X emissions reduction standard, EPA has concluded, compares well with the cost effectiveness of other existing and planned mobile and stationary NO_X control programs, as summarized in *Table 6*.

Estimates of the costs and cost effectiveness of California reformulated gasoline continue to decline. At the time it developed its regulations, CARB estimated the costs to be $0.12 to $0.17 per gallon. An analysis by Dr. R. Dwight Atkinson of EPA's Office of Policy, Planning and Evaluation (*The Case for California Reformulated Gasoline — Adoption by the Northeast,* May 1993) placed the costs at $0.08 to $0.11 per gallon. This analysis estimated the cost effectiveness of California reformulated gasoline to be $4100 to $5100 per ton of VOC and NO_X controlled.

Federal Rulemaking and/or Guidance Documents

On February 16, 1994 (59 *Federal Register* 7716), EPA published a final rule implementing the reformulated gasoline requirements mandated by Section 211(k) of the Clean Air Act Amendments of 1990. The primary program under that rule requires that gasoline in the nine worst ozone nonattainment areas be reformulated to reduce ozone-forming VOCs and toxics. Other areas may opt into this program. A second program under the rule prohibits gasoline sold in the rest of the United States from becoming more polluting.

The reformulated gasoline regulations take effect January 1, 1995. Under Phase I (1995-1999), VOC and toxic emissions will be reduced by 15 percent, compared to baseline fuels. Under Phase II, VOC emissions will be reduced on average by 25.9 percent (control region 1) and 27.4 percent (control region 2), and NO_X by 6.8 percent. Toxic emissions must be reduced by 20 percent on a per gallon basis.

On December 27, 1993 (58 *Federal Register* 68343) EPA proposed a requirement that 30 percent of the oxygen content of reformulated gasoline come from renewable oxygenates. EPA identified several possible emission impacts resulting from the requirement, but these did not include any impact on NO_X emissions. This rule was made final on June 30, 1994.

On August 21, 1990 (55 *Federal Register* 34120) EPA adopted its low-sulfur fuel standard of 0.05 percent by weight, which took effect October 1, 1993. On May 7, 1992 (57 *Federal Register* 19535) EPA amended its regulations to conform to the requirements of the CAAA of 1990.

State and Local Control Efforts

States have traditionally led the way in regulating fuel composition to lower emissions. Perhaps the two most significant efforts have been the adoption of reformulated gasoline requirements by California and the adoption of low-RVP requirements by the northeastern states. In addition, as of May 1994, all 13 states of the Ozone Transport Region, along with the Louisville, KY and Dallas/Fort Worth, TX areas, have opted into the federal reformulated gasoline program, while three counties in Wisconsin recently requested to opt into the program.

References

1. U.S. Environmental Protection Agency, Office of Mobile Sources. February 16, 1994. *Regulation of Fuels and Fuel Additives: Standards for Reformulated Gasoline. Final Rule.* (59 *Federal Register* 7716).

2. U.S. Environmental Protection Agency, Office of Mobile Sources. April 16, 1992. *Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline. Supplemental Notice of Proposed Rule.* (57 *Federal Register* 13416).

3. U.S. Environmental Protection Agency, Office of Mobile Sources. February 26, 1993. *Regulation of Fuels and Fuel Additives: Standards for Reformulated Gasoline.* Proposed Rule. (58 *Federal Register* 11722).

4. California Air Resources Board. October 4, 1991. *Proposed Regulations for California Phase 2 Reformulated Gasoline Staff Report.*

5. California Air Resources Board, April 22, 1994. *Proposed Amendment to the Reformulated Gasoline Regulations, Including Amendments Providing the Use of a Productive Model.*

Table 1

Parameter Ranges for Which the Complex Model Can Be Used

Fuel Parameter	Valid Range for Fuel Type: Reformulated Fuel	Valid Range for Fuel Type: Conventional Fuel
Aromatics, vol %	0-50	0-55
E200, %	30-70	30-70
E300, %	70-100	70-100
Olefins, vol %	0-25	0-30
Oxygen, vol %	0-3.7	0-3.7
RVP, psi	6.4-10	6.4-11
Sulfur, ppm	0-500	0-1000
Benzene, vol %	0-2.0	0-4.9

Source: EPA.

Table 2

Reformulated Gasoline Performance Standards Relative to Clean Air Act Baseline Gasoline for 1998-1999

	VOC Control Region 1		VOC Control Region 2	
Emission	Average (%)	Per Gallon (%)	Average (%)	Per Gallon (%)
VOC	-36.6	-35.1	-17.1	-15.6
Toxics	-16.5	-15.0	-16.5	-15.0
NO_X	-1.5	0.0	-1.5	0.0

Source: EPA.

Table 3

Standards for Federal Phase II Reformulated Gasoline (Percent reduction in emissions)

Controlled Emission	VOC Control Region 1	VOC Control Region 2
VOC:		
Per Gallon	27.5[1]	25.9
Averaging	29.0	27.4
Minimum	25.0	23.4
NO_X:		
Per Gallon	5.5	5.5
Averaging	6.8	6.8
Minimum	3.0	3.0

Source: EPA.

[1]*Reductions relative to a base fuel with RVP at 7.8 psi on a per-gallon basis would be 17.2% for VOC and 5.3% for NO_X.*

Table 4

Standards for Gasoline in California (All standards to take effect in 1996)

	Flat Limit	Averaging Limit	Cap Limit
Reid Vapor Pressure (psi, max.)	7.0	none	7.0
Sulfur (ppmw, max.)	40.0	30.0	80.0
Benzene (vol.%, max.)	1.0	0.8	1.2
Aromatic HC (vol.%, max.)	25.0	22.0	30.0
Olefins (vol.%, max.)	6.0	4.0	10.0
Oxygen (wt.%)	1.8 to 2.2	none	2.7 (max.)
Temperature at 50% distilled (deg.F, max.)	210.0	200.0	220.0
Temperature at 90% distilled (deg.F, max.)	300.0	290.0	330.0

Source: California Air Resources Board.

Table 5

Fuel Parameter Control Costs and NO_x Reductions[1]

Fuel Parameter Control	Incremental Cost (¢/gal)	Cumulative Reduction (%)	Incremental Cost Effectiveness ($/ton)	Incremental to Phase 1 ($/ton)[2]
Phase 1:				
RVP: 8.0 psi, Oxygen: 2.1 wt percent, Benzene: 0.95 percent				
RVP to 6.7 psi	—	0.4	—	—
Sulfer to 250 ppm	0.12	2.4	1,300	3,200
Sulfur to 160 ppm	0.56	5.8	3,700	3,500
Sulfur to 138 ppm	0.24	6.8	5,200	3,700
Sulfur to 100 ppm	0.52	8.7	6,200	4,200
Olefins to 8.0 vol percent	0.78	10.8	8,000	5,000
Aromatics to 20 vol. percent	2.01	11.9	40,000	8,200
Oxygen to 2.7 vol percent	0.61	12.5	25,000	8,900
Olefins to 5.0 vol percent	2.77	14.1	37,000	12,000
E300 to 88 percent	0.35	14.1	(–)	13,000
E300 to 91 percent	2.01	14.2	820,000	16,000
E200 to 44 percent	0.38	13.9	(–)	17,000
E200 to 47 percent	1.32	13.7	(–)	19,000
E200 to 50 percent	2.97	13.5	(–)	24,000

Source: EPA.

[1]*Based on costs and emissions reductions for VOC control region 2 (northern areas). Assumes all costs allocated to NO_x control. Cost effectiveness values will be slightly lower if credit is given for the VOC reductions that also result from some of the fuel changes.*

[2]*NO_x cost effectiveness incremental to a Phase II VOC standard would be slightly lower, especially for the first few increments.*

Table 6

Cost Per Ton of Various NO_x Control Strategies

Control Measure	Cost ($/ton NO_x)
Phase II Reformulated Gasoline	$3200
Tier I LDV Emission Standards	$2,000-$6,000
Increasing Stringency of I/M Cutpoints	$4,000-$8,000
Low NO_x Burners	up to $1,000
Selective Catalytic Reduction	$3,000-$10,000

Source: EPA.

California Low-Emission Vehicles

Description of Control Measures

Section 177 of the Clean Air Act Amendments of 1990 provides states with authority to adopt, or "opt into," the California low-emission vehicle (LEV) program standards, which are substantially more stringent than the federal motor vehicle standards. The LEV program adopted by the California Air Resources Board (CARB) includes light- and medium-duty motor vehicle emissions standards that will progressively reduce emissions from model years 1994 through 2003.

Beginning in 1994, each vehicle may be certified to any one of the sets of standards identified in *Table 1*. Emissions standards for the transitional low-emission vehicle (TLEV), the low-emission vehicle (LEV), the ultra-low-emission vehicle (ULEV) and the zero-emission vehicle (ZEV) are known collectively as the LEV standards. These standards impose a limit on emissions of non-methane organic gas (NMOG), that differ from non-methane hydrocarbons (NMHC) in that NMOG contains oxygen-bearing compounds, such as aldehydes, in addition to hydrocarbons. In the case of a vehicle certified with conventional (unreformulated) gasoline, the mass emissions of NMOG as directly measured will be compared to the NMOG standards shown in *Table 1*. For other fuels, including reformulated gasoline, the mass measured emissions will be adjusted according to reactivity (ozone potentially formed per gram of emissions) before a comparison to the standard is made. As a result, the NMOG standards are equivalent to standards for ozone-forming potential that are of uniform stringency for all fuels.

For any model year after 1993, each manufacturer's vehicle sales in California must be a combination of conventional and low-emission vehicles, such that the average certification standard for NMOG (or NMHC) does not exceed the value identified in *Table 2*. In addition, 2 percent of each manufacturer's new vehicles in 1998 must be ZEVs; this requirement increases gradually to 10 percent for the 2003 model year. Slightly different requirements exist for flexible- and dual-fueled vehicles, as shown in *Table 3*.

The effectiveness of emissions standards can be substantially affected by the manner in which they are enforced. Beyond more stringent standards, the California LEV program has been distinguished by a consistent move toward greater manufacturer responsibility for in-use emissions.

STAPPA/ALAPCO
Recommendation

▶ States should seriously consider adopting the California LEV program, which offers significant air quality benefits—including NO_X reductions—in the post-2005 time frame, when additional mobile source emissions reductions may be difficult to obtain.

For example, under the California program, defect reporting and recall is a specific requirement. Beginning with the 1990 model year, CARB regulations require manufacturers to report all warranty claims for emissions-related components that occur at a rate of 4 percent or more. Unless the manufacturer can show that the true failure rate is below these reporting thresholds or that the emissions impact is negligible, a recall of the vehicles using the failing components is required.

When a recall is required, the minimum acceptable success rate is 60 percent (for voluntary recalls). If the recall is ordered by CARB, the required success rate is increased to 80 percent. By comparison, only about 55 percent of cars recalled under the federal program are actually repaired, although, under the new requirements, in areas implementing enhanced I/M, 100 percent of recalled vehicles will be required to be repaired.

Available Control Strategies

According to MOBILE5a, the benefits associated with adoption of the California program are dependent on the type of I/M program adopted and the type of fuel used. This was clarified in guidance from EPA on April 8, 1994, which recommends an I/M program for LEVs that is equivalent to the enhanced I/M program for federal Tier I vehicles. The major difference between enhanced I/M for Tier I vehicles and LEV vehicles is the cutpoints to be used. IM240 cutpoints of 0.6 THC, 10 CO and 1.2 NO_X for light-duty LEV vehicles are required, compared to Tier I cutpoints of 0.7, 10 and 1.4, respectively.

Based on this guidance, the approach that was modeled assumes that the LEV program is adopted for the 1996 model year, along with enhanced I/M and federal reformulated gasoline. MOBILE5a models federal reformulated gasoline in accordance with EPA's proposal of February 26, 1993, which does not require any improvement in NO_X emissions. EPA's final reformulated gasoline rule, adopted on February 16, 1994, requires a 6.8-percent NO_X reduction. EPA intends to modify MOBILE5a to account for this additional reduction, but it has not yet done so.

The reductions currently calculated by MOBILE5a tend to understate the NO_X benefits from federal reformulated gasoline after the year 2000. Since the 6.8-percent reduction only applies to gasoline-fueled vehicles and will probably achieve its full benefit only on 1986 and newer model year light-duty vehicles, the overall incremental impact will be substantially below 6.8 percent. In a second scenario, LEV is coupled with enhanced I/M and California reformulated gasoline.

As time passes, it will no longer be possible, based on the lead time requirements of the Clean Air Act, for most states to adopt the LEV program by 1996. Therefore, additional modeling runs were conducted, assuming that the LEV program is mandated in 1999.

Potential National Emissions Reduction

Figures 1 through 3 illustrate the emissions reduction potential of each of the above scenarios, assuming that LEV is introduced in 1996. *Figures 4 through 6* summarize the impacts assuming introduction in 1999. It is clear that the LEV program is capable of very substantial additional reductions in NO_X emissions. For example, if coupled with enhanced I/M and federal RFG and introduced in 1996, NO_X reductions would be approximately 7 percent by 1999 and 25 percent by 2005. If the LEV program is coupled with California reformulated gasoline, the reductions increase to 13 percent in 1999 and 30 percent by 2005. If introduction is delayed until 1999, although any incremental reductions prior to that time are eliminated, as illustrated in *Figures 4, 5 and 6*, the NO_X gains will grow rapidly immediately after introduction.

Table 4 summarizes CARB's analysis of the emissions reduction potential of a low-emission vehicle compared to a Tier 1 vehicle.

Costs and Cost Effectiveness

CARB has recently performed an extensive review of the available information and has met with many industry representatives and other interested parties in its efforts to provide the best possible assessment of the technological and commercial feasibility of the requirements of the LEV program. Based on this review, CARB has concluded that the incremental costs per vehicle are low. The incremental average cost per vehicle of TLEVs is estimated to be \$61, while that estimate for LEVs is \$114 and for ULEVs, \$221 (see *Table 5*).

The cost effectiveness of low-emission vehicles is estimated to be less than $1.00 per pound of emissions reduced (as indicated in *Tables 6 and 7*). The incremental cost of ULEVs relative to LEVs is only $1.59 per pound of emissions reduced. Even if these CARB cost estimates for low-emission vehicles are off by a factor of ten, the program would still be cost effective relative to other control measures.

State and Local Control Efforts

Several states in the northeast have adopted or are considering adoption of the LEV program. For example, New York, Massachusetts and Maine have adopted the LEV program. The auto industry has challenged the New York and Massachusetts programs in court and the litigation is still pending. The Maryland and New Jersey legislatures have also approved legislation authorizing implementation of the LEV program.

State adoption of the California LEV program was endorsed when the Ozone Transport Commission (OTC) voted February 1, 1994, in favor of submitting a petition to EPA recommending region-wide implementation of the "OTC LEV program." The OTC, which consists of all the northeast and mid-Atlantic states from Virginia to Maine, including the Washington D.C. metropolitan area, has legal authority under the CAAA to recommend regional air pollution control strategies to EPA. The OTC's newly approved petition will be the first official recommendation. Seven affirmative votes were required to approve the recommendation; in fact, nine states voted in favor of it.

The OTC's recommended LEV program, called the "OTC LEV program," is very similar to the California LEV program. As *Table 8* illustrates, the fleet NMOG emission average for the OTC LEV program is identical to that of the California LEV program.

Like the California LEV program, the recommended OTC LEV program allows for five categories of vehicles: California Tier I Vehicles, TLEVs, LEVs, ULEVs and ZEVs. Under the proposed OTC LEV program, any vehicle sold in the Ozone Transport Region must be certified to the California standards by CARB. As *Table 8* indicates, this requirement would apply beginning in the 1999 model year.

The two differences between the proposed OTC LEV program and the California LEV program relate to 1) California reformulated gasoline and 2) the ZEV mandate.

First, the OTC LEV program would not require use of California RFG. Second, if legally acceptable under provisions of the CAAA, the OTC LEV program also would not include a ZEV mandate. However, under the proposed OTC LEV program, auto manufacturers could sell ZEVs to meet their required fleet average, and individual states would have the option of instituting their own mandatory or voluntary ZEV programs. The OTC LEV proposal also does not preclude states within the OTC from early implementation of the LEV program (i.e., prior to model year 1999). This means that the OTC LEV program would not affect the New York and Massachusetts LEV programs, which, to date, include the ZEV mandate and are slated to begin earlier than the 1999 model year.

EPA is now responsible for analyzing the feasibility of implementing a region-wide low-emission vehicle program, formulating the specific provisions of a program and initiating the official rulemaking process. A final decision by EPA is required by November 1994.

References

1. U.S. Environmental Protection Agency. April 8, 1994. *Emissions Reduction Credits for California Low-Emission Vehicles (LEV).*

2. California Air Resources Board. April 1994. *Staff Report: 1994 Low-Emission Vehicle and Zero-Emission Vehicle Program Review.*

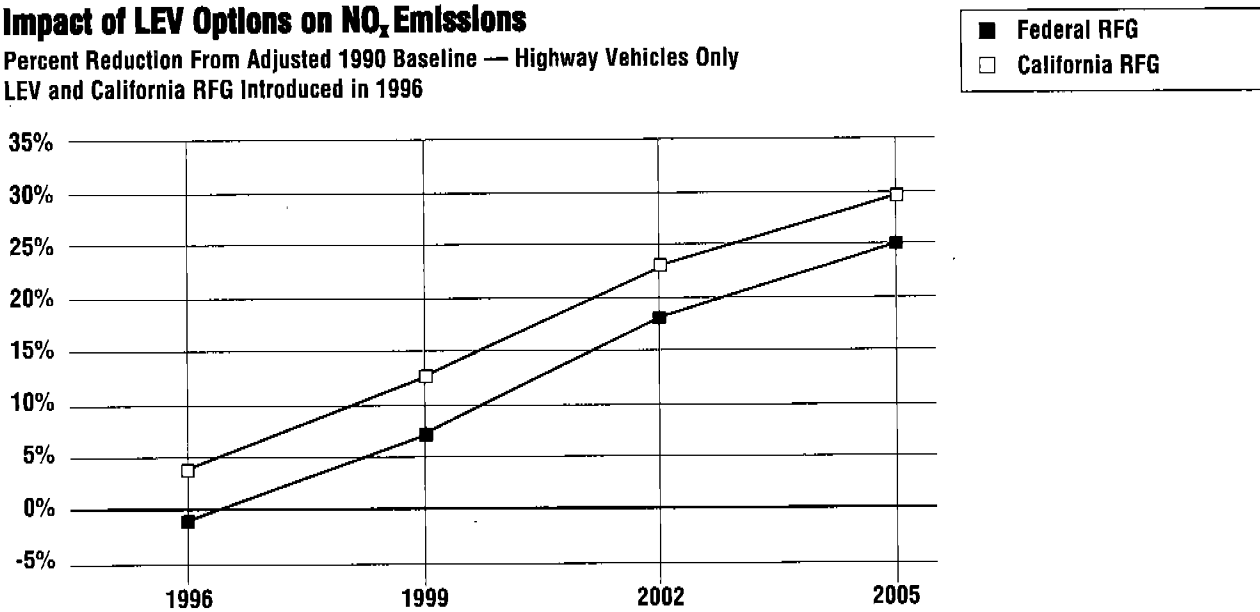
3. Mid-Atlantic Regional Air Management Association. December 1992. *Adopting the Low-Emission Vehicle Program in the Mid-Atlantic States.*

4. Northeast States for Coordinated Air Use Management. September 1991. *Adopting the Low-Emission Vehicle Program in the Mid-Atlantic States: An Evaluation.*

Figure 1

Impact of LEV Options on NO_x Emissions

Percent Reduction From Adjusted 1990 Baseline — Highway Vehicles Only
LEV and California RFG Introduced in 1996

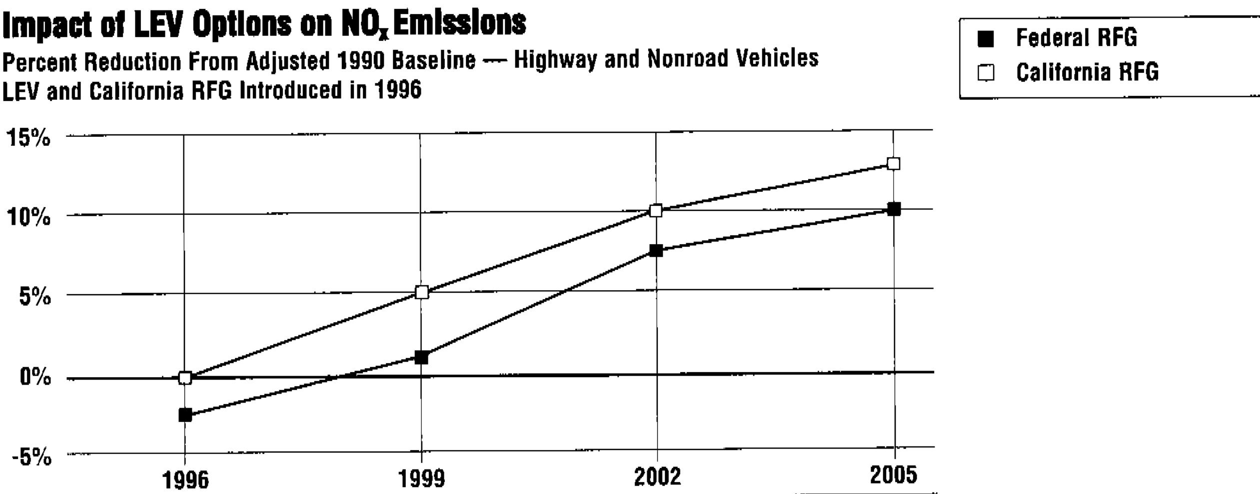


	1996	1999	2002	2005
Federal RFG	-1%	7%	18%	25%
California RFG	4%	13%	23%	30%

Figure 2

Impact of LEV Options on NO_x Emissions

Percent Reduction From Adjusted 1990 Baseline — Highway and Nonroad Vehicles
LEV and California RFG Introduced in 1996



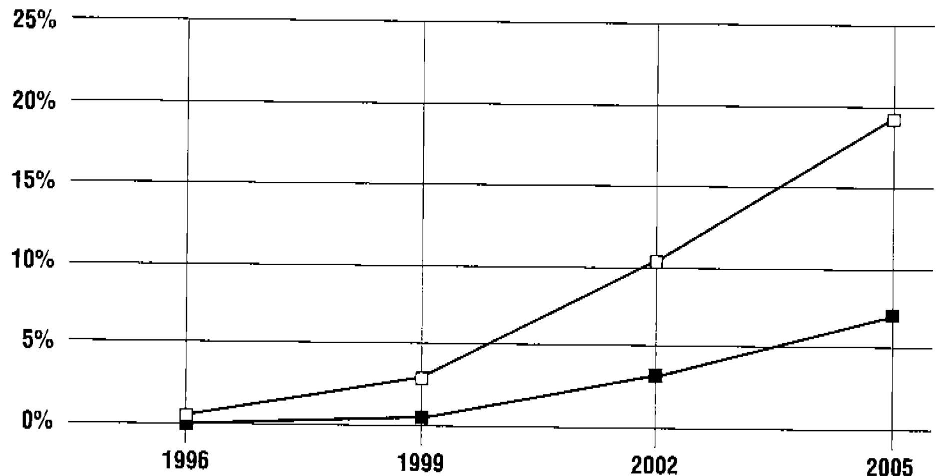
	1996	1999	2002	2005
Federal RFG	-3%	1%	7%	10%
California RFG	0%	5%	10%	13%

Figure 3

Incremental Benefits of LEV Over Tier 1

Percent Reduction in NO_x Emissions — Highway Vehicles Only with Federal RFG
LEV Introduced in 1996

■ Total Reduction
□ Incremental vs. Tier 1



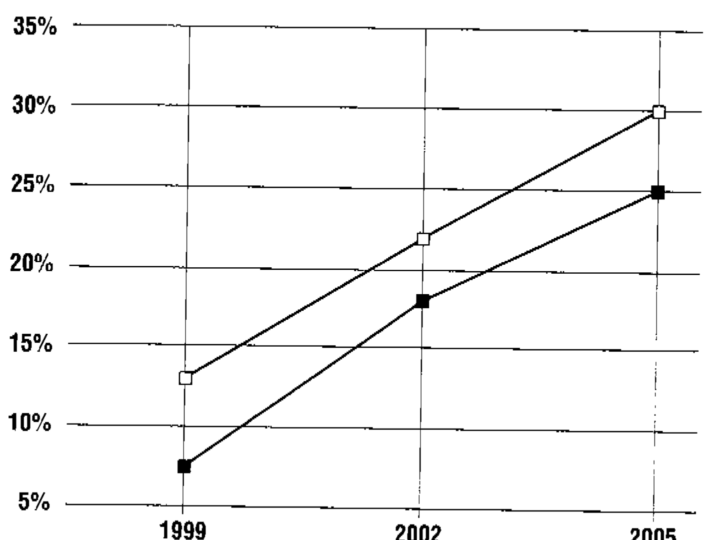
	1996	1999	2002	2005
Total Reduction	0.0%	0.5%	3.7%	7.4%
Incremental vs. Tier 1	0.5%	3.4%	10.5%	19.2%

Figure 4

Impact of LEV Options on NO_x Emissions

Percent Reduction From Adjusted 1990 Baseline — Highway Vehicles Only
LEV and California RFG Introduced in 1999

■ Federal RFG
□ California RFG

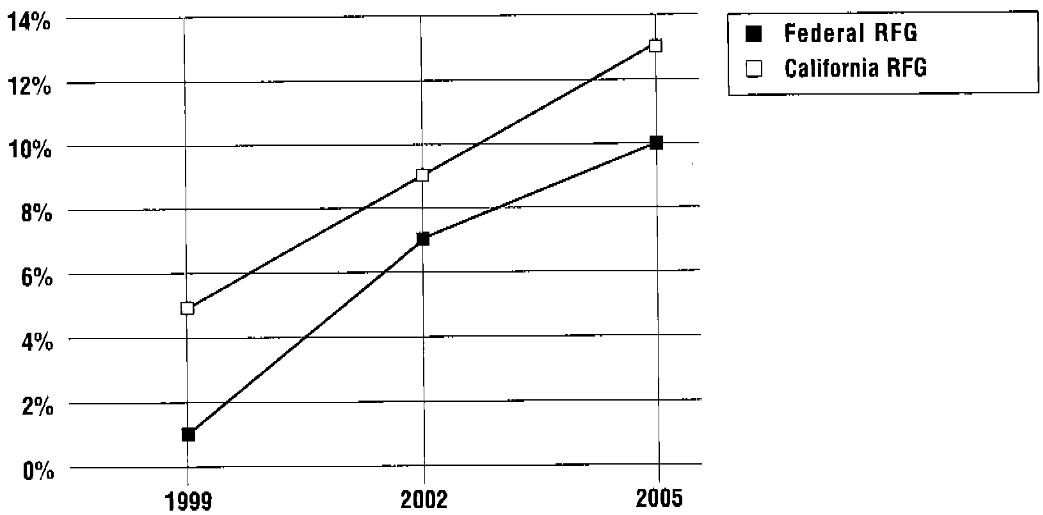


	1999	2002	2005
Federal RFG	7%	18%	25%
California RFG	13%	22%	30%

Figure 5

Impact of LEV Options on NO_x Emissions

Percent Reduction From Adjusted 1990 Baseline — Highway and Nonroad Vehicles
LEV and California RFG Introduced in 1999

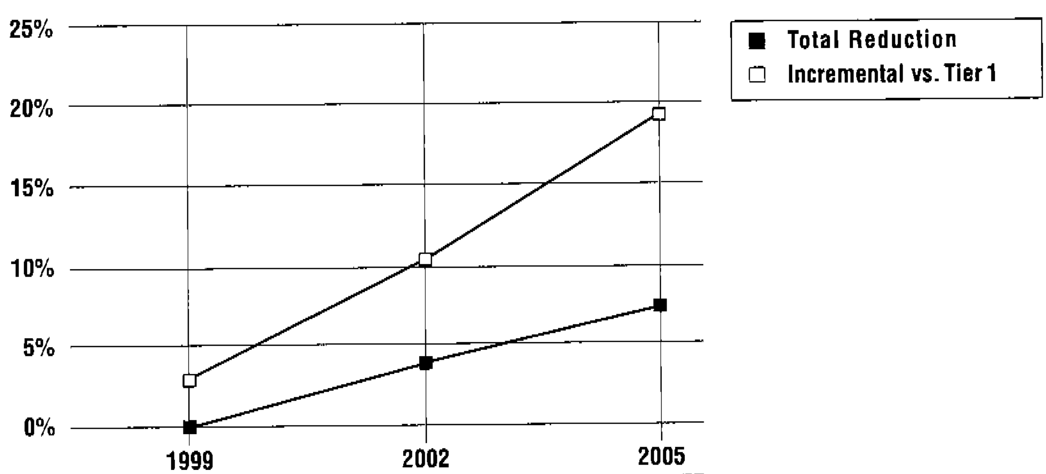


	1999	2002	2005
Federal RFG	1%	7%	10%
California RFG	5%	9%	13%

Figure 6

Incremental Benefits of LEV Over Tier 1

Percent Reduction in NO_x Emissions—Highway Vehicles Only With Federal RFG
LEV Introduced in 1999



	1999	2002	2005
Total Reduction	0.0%	3.7%	7.4%
Incremental vs. Tier 1	2.9%	10.5%	19.2%

Table 1

50,000-Mile Certification Standards (gpm)

Category	NMHC	NMOG[1]	CO	NO_x
Conventional	0.25	—	3.4	0.4
TLEV	—	0.125	3.4	0.4
LEV	—	0.075	3.4	0.2
ULEV	—	0.040	1.7	0.2
ZEV	—	0	0	0

Source: California Air Resources Board.
[1]The standard applies to emissions that have been reactivity-adjusted to the gasoline basis.

Table 2

Fleet Average Standards for NMOG for Passenger Cars and Light-Duty Trucks (gpm)

Model Year	Fleet Average Standard for NMOG[1]
1994	0.250
1995	0.231
1996	0.225
1997	0.202
1998	0.157
1999	0.113
2000	0.073
2001	0.070
2002	0.068
2003	0.062

Source: California Air Resources Board.
[1]The standard applies to emissions that have been reactivity-adjusted to the gasoline basis.

Table 3

NMOG Standards for Flexible- and Dual-Fueled Passenger Cars Operating on an Alternative Fuel and Gasoline at 50,000 Miles (gpm)

Category	Alternate Fuel[1]	Gasoline
TLEV	0.125	0.250
LEV	0.075	0.125
ULEV	0.040	0.075

Source: California Air Resources Board.
[1]The standard applies to emissions that have been reactivity-adjusted to the gasoline basis.

Table 4

Emission Reductions from a Low-Emission Vehicle Compared to a Tier I Vehicle

Category	Lifetime ROG Emissions (lbs.)	Lifetime NO_x Emissions (lbs.)	Lifetime CO Emissions (lbs.)	ROG+NO_x Emiss. Red. (lbs.)	ROG Emiss. Red. (lbs.)	ROG+NO_x+CO/7 Emiss. Red. (lbs.)
Tier I	85.14	141.1	1258.5	—	—	—
TLEV	45.55	141.1	914.5	39.59	39.59	88.74
LEV	23.90	70.6	823.1	131.74	61.24	193.93
ULEV	13.17	70.6	427.1	142.47	71.97	261.24

Source: California Air Resources Board.

Table 5

Incremental Cost of Low-Emission Vehicles Compared to a Tier I Vehicle

Category	Incremental Cost Estimate in 1994 ($)
TLEV	60.67
LEV	113.94
ULEV	220.91

Source: California Air Resources Board.

Table 6

Cost Effectiveness of Low-Emission Vehicles Compared to a Tier I Vehicle

Category	$ROG+NO_x$[1] ($/lb)	ROG[1] ($/lb)	$ROG+NO_x+CO/7$[2] ($/lb)
TLEV	0.77	0.77	0.68
LEV	0.43	0.93	0.59
ULEV	0.78	1.53	0.85

Source: California Air Resources Board.

[1] It is assumed that one-half of the added cost is allocated towards criteria pollutant reductions and the other half towards toxic air contaminant reductions.

[2] Based on "California Clean Air Act: Cost-effectiveness Guidance," September 1990.

Table 7

Incremental Cost Effectiveness of Low-Emission Vehicles (dollars/pound of pollutant reduced)

Category	$ROG+NO_x$[1]	ROG[1]	$ROG+NO_x+CO/7$[2]
TLEV	0.77	0.77	0.68
LEV	0.29	1.23	0.51
ULEV	4.98	4.98	1.59

Source: California Air Resources Board.

[1] It is assumend that one-half of the added the cost is allocated towards criteria pollutant reductions and other the half towards toxic air contaminant reductions.

[2] Based on "California Clean Air Act: Cost-effectiveness Guidance," September 1990.

Table 8

OTC LEV Program Fleet NMOG Emission Average

Model Year	Fleet Average Standard (g/mi)
1999	0.113
2000	0.073
2001	0.070
2002	0.068
2003 and later	0.062

Source: Ozone Transport Commission.

Clean-Fuel Fleets

Description of Control Measure

Provisions of the Clean Air Act Amendments of 1990 (CAAA) require the establishment of a clean-fuel fleet program in certain ozone and carbon monoxide nonattainment areas. Accordingly, 22 areas in 19 states are obligated to modify their State Implementation Plans (SIPs) to require that some of the new vehicles purchased by certain fleet owners meet clean-fuel fleet vehicle (CFFV) exhaust and evaporative emissions standards. Under the CAAA, a clean fuel is defined as any fuel, including any gasoline or diesel, that will allow the vehicle to achieve mandated emissions standards. In addition, EPA has established a subgroup of CFFVs, known as inherently low-emission vehicles (ILEVs). This federal program, which is voluntary for both vehicle manufacturers and the fleet industry, grants expanded exemptions from transportation control measures (TCMs) to ILEVs in recognition of their superior emission characteristics.

Initially, ILEVs will receive exemptions from high-occupancy vehicle (HOV) lane restrictions; EPA has announced that it will propose additional exemptions/incentives at a future time. These exemptions are intended to provide further incentives to fleet owners to purchase cleaner vehicles than otherwise required by the statute.

Section 246(b) of the CAAA directs states that contain areas subject to the CFFV program to require that "at least a specified percentage of all new covered fleet vehicles in model year 1998 and thereafter purchased by each covered fleet operator in each covered area shall be clean-fuel vehicles and shall use clean alternative fuels when operating in the covered area." The 19 states that contain affected areas are required to revise their SIPs to include programs that ensure that covered fleet owners meet this purchase requirement when they acquire vehicles for their fleets. Covered fleet owners will retain discretion regarding other choices about vehicle purchases, such as the fuel technology of the vehicles.

A CFFV is one that meets any one of three sets of CFFV exhaust emissions standards. The emissions standards and the vehicles that meet them are referred to as low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs) and zero-emission vehicles (ZEVs). Only LEVs are required to be purchased under the statute; affected fleet operators purchasing ULEVs and ZEVs in lieu of LEVs will receive purchase credits against the CFFV purchase requirements. Three vehicle classes are

STAPPA/ALAPCO
Recommendation

▶ Areas not required by the Clean Air Act to implement a CFFV program should consider adoption of such a program. To increase the reduction potential of a CFFV program, areas already required to implement such a program may wish to consider purchasing more CFFVs than required in any year, purchasing vehicles that meet stricter emission standards than those required or purchasing vehicles in advance, before requirements take effect. States may also encourage non-covered fleets to participate. Where fleet requirements from the Energy Policy Act are also applicable, states should consider requiring the purchase of ILEVs, which offer substantial NO_X benefits beyond the Tier I motor vehicle standards.

covered by the program: light-duty vehicles and trucks (LDVs and LDTs) under 6000 lb Gross Vehicle Weight Rating (GVWR); LDTs between 6000 lb and 8500 lb GVWR; and heavy-duty vehicles (HDVs) over 8500 lb GVWR, but under 26,000 lb GVWR.

The CAAA prescribe purchase requirements in terms of a percentage of the total number of new covered fleet vehicles of each class purchased each year by an affected fleet operator. The purchase requirements begin with model year 1998 vehicles. For light-duty vehicles and light-duty trucks, this date may be extended by up to three years if the appropriate vehicles are not available for sale in California. The program's purchase requirements are phased in over three years. Two phase-in schedules are specified, one for LDVs and LDTs and one for HDVs, as shown in *Table 1*.

The requirements of this program can be met by purchasing new vehicles that meet the CFFV LEV, ULEV or ZEV standards or by converting conventional vehicles to CFFVs that meet the applicable standards.

There are currently 22 covered areas in 19 states affected by the CFFV program; these areas are identified in *Table 2*. At this time, the only affected carbon monoxide nonattainment area that is not also classified as an ozone nonattainment area, based on 1987-1989 data, is the Denver-Boulder, Colorado area. *Table 3* provides EPA's estimate of the numbers of CFFVs that will be in use by the year 2010.

AVAILABLE CONTROL STRATEGIES

A state may reduce emissions not only by requiring the purchase of the necessary CFFVs, but also by encouraging the purchase of more CFFVs than required in any year, the purchase of vehicles that meet stricter emission standards than those required, or the advance purchase of vehicles, before requirements take effect. States may also encourage non-covered fleets to participate.

The incorporation of ILEVs into the CFFV program will result in additional hydrocarbon reductions, due to the lower evaporative emissions from ILEVs, but will not provide additional NO_X emissions reductions beyond those achieved by vehicles meeting the LEV or ULEV standards.

Vehicle models that manufacturers wish to certify as ILEVs must meet two primary criteria. First, the vehicle's engine/fuel system must be certified to meet the ILEV non-methane organic gas evaporative emissions standard; second, the vehicle must meet the ILEV exhaust emissions standards (identified in *Table 4*).

The ILEV evaporative emissions standard of 5 grams per test must be met without the use of any auxiliary emissions control devices to reduce or control evaporative emissions (e.g., carbon canister, purge system). Based upon limited data, EPA projects that the 5-gram evaporative standard will permit vehicles that operate on very low-volatility fuels (such as pure ethanol and pure methanol), as well as pressurized gaseous fuels (compressed natural gas [CNG], liquefied petroleum gases [LPG] and hydrogen), to potentially qualify as ILEVs. In addition, it is expected that dedicated electric vehicles would meet the ILEV evaporative emissions standard. EPA believes that vehicles operating on some formulations of petroleum fuels may also meet the ILEV standard and would therefore qualify as ILEVs.

The ILEV program is limited to dedicated-fuel vehicles and dual-fuel vehicles that are certified as ILEVs on both fuels. Due to the critical role of the fuel in the emissions of the vehicle, and the difficulty of enforcement, flexible-fuel and dual-fuel vehicles that do not qualify as ILEVs on all possible fuels and fuel combinations can not be considered ILEVs.

It is important to note that there is a parallel alternative fuels program mandated by the Energy Policy Act of 1992. Under this law, federal fleets are required to phase in alternative fuels in their new purchases beginning in 1993. As illustrated in *Figure 1*, President Clinton has issued an Executive Order increasing the federal fleet purchase requirements by 50 percent between 1993 to 1995. Beyond this time frame, federal, state, municipal, private and fuel provider alternative fuel fleet purchase requirements increase significantly. As a result, it is likely that fueling facilities for alternative fueled vehicles will begin to be more widely available, increasing the viability of alternative fuel and ILEV vehicles.

Potential National Emissions Reduction

For the purposes of this document, MOBILE5a was used to estimate the possible reductions that could occur from two alternatives: 1) the purchase of 10,000 CFFVs in 1996 meeting either LEV, ULEV, ZEV or ILEV requirements and 2) the purchase of 10,000 vehicles per year beginning in 1996 meeting either LEV, ULEV, ZEV or ILEV requirements. For each case, two alternative I/M programs were modeled — enhanced and "appropriate." (The program described here as "appropriate" I/M is identical to that described in EPA's April 8, 1994 memorandum on SIP credits for the California low-emission vehicle program, entitled *Emissions Reduction Credits for California Low-Emission Vehicles*.) The light-duty ILEV standards are shown in *Table 4* and the proposed heavy-duty ULEV standards are listed in *Table 5*.

The results, presented as tons reduced on a typical summer day, are summarized in *Figures 2 through 5*. As illustrated, the benefits of purchasing 10,000 vehicles in 1996 are modest, but not insignificant. ILEVs and ZEVs will provide greater credits than LEVs or ULEVs and the overall benefits are higher with "appropriate" I/M than with enhanced I/M. If 10,000 vehicles per year were to be purchased beginning in 1996, the benefits would increase rapidly and would be quite significant, especially for ZEVs and ILEVs. The benefits derived will depend on the strategy selected.

In both of the above scenarios, ZEVs were assumed to emit zero emissions. While the vehicles themselves would have no emissions, it is generally agreed that emissions from power plants providing electricity for ZEVs should be allocated to these vehicles. These per-vehicle emission factors will vary depending upon the mix of power plant fuels used in a given state or region. Emission factors will also vary depending upon the vehicle's battery technology and physical characteristics. An assessment of these issues was carried out for the northeast region by the Northeast States for Coordinated Air Use Management, with resulting emissions factors summarized in *Table 6*.

Costs and Cost Effectiveness

For the purposes of evaluating the CFFV program, the cost effectiveness of the various LEV categories should be similar to those estimated for the California LEV program.

Federal Rulemaking and/or Guidance Documents

On March 1, 1993 EPA published its final rule establishing the clean-fuel fleet credit program and the associated transportation control measure exemptions (58 *Federal Register* 11888).

On June 10, 1993, EPA published a proposed rule addressing clean-fuel fleet emissions standards, conversions, averaging and accounting procedures for banking and trading credits (58 *Federal Register* 32474).

On June 23, 1993 EPA proposed the California pilot test program and clean-fuel vehicle standards for light-duty vehicles and light-duty trucks (58 *Federal Register* 34727).

On December 9, 1993, EPA issued final rules containing the definitions and general provisions of the clean-fuel fleet program (58 *Federal Register* 64679).

On June 14, 1994, EPA announced a final rule promulgating clean-fuel fleet vehicle standards.

State and Local Control Efforts

Several states have proposed or are considering alternatives to the federal clean-fuel fleet program (*Table 7*). Some are pursuing adoption of the California LEV Program, which should yield substantially greater NO_X emissions reductions than the CFFV program because, while the NO_X standards are comparable, the number of vehicles covered under the LEV program are substantially greater. Other state programs are focusing on promoting alternative fuels for environmental, energy and/or economic reasons and not necessarily for NO_X reductions, *per se*.

The Texas Natural Resource Conservation Commission, for example, has proposed the Texas Alternative Fuel Fleet (TAFF) Program as an alternative to the federal program. The primary distinction between the federal program and the Texas program is that Texas requires that fleet vehicles meet the LEV standards using only "alternative fuels," such as propane, natural gas, methanol, ethanol and electricity. The state's primary objective in developing TAFF is to increase usage of alternative fuels. Given that the federal and Texas programs' tailpipe emission standards and other provisions are fairly similar, the two programs should achieve similar NO_X emissions reductions.

This conclusion may also hold true for the ILEV program being considered in New Hampshire, as well as the ILEV Fleet Initiative of the Northeast States for Coordinated Air Use Management. Since the central distinction between the ILEV standard and the CFFV standard is the ILEV's tight evaporative emissions standard, the ILEV program likely would not lower NO_X emissions beyond those achievable through the federal CFFV program. However, in as much as these programs are designed also to fulfill the vehicle conversion mandate under the federal Energy Policy Act of 1992, implementation of ILEV programs may result in increased NO_X reductions if they include wider vehicle coverage.

If the New Hampshire legislature approves the ILEV program, New Hampshire will be the first state to adopt EPA's voluntary program.

References

1. U.S. Environmental Protection Agency, Office of Mobile Sources. June 14, 1994. *Clean-Fuel Fleet Vehicle Standards*. Final Rule.

2. U.S. Environmental Protection Agency, Office of Mobile Sources. December 9, 1993. *Definitions and General Provisions of the Clean-Fuel Fleet Program.* Final Rule. (58 *Federal Register* 64679).

3. U.S. Environmental Protection Agency, Office of Mobile Sources. June 23, 1993. *California Pilot Test Program and Clean-Fuel Vehicle Standards for Light-Duty Vehicles and Light-Duty Trucks*. Proposed Rule. (58 *Federal Register* 34727).

4. U.S. Environmental Protection Agency, Office of Mobile Sources. June 10, 1993. *Clean-Fuel Fleet Emission Standards, Conversions, and General Provisions and Amended Heavy-Duty Averaging, Banking and Trading Credit Accounting Regulations*. Proposed Rule. (58 *Federal Register* 32474).

5. U.S. Environmental Protection Agency, Office of Mobile Sources. March 1, 1993. *Clean-Fuel Fleet Credit Program and Transportation Control Measures Exemptions*. Final Rule. (58 *Federal Register* 11888).

6. U.S. Department of Energy, Office of Transportation Technologies. May 1993. *Clean Cities Program Plan*.

7. Office of the President. April 21, 1993. *Executive Order 12844: Federal Use of Alternative Fueled Vehicles*.

Figure 1

Federal Fleet Purchase Requirements for Alternative Fuel Vehicles

Energy Policy Act of 1992 Versus Executive Order

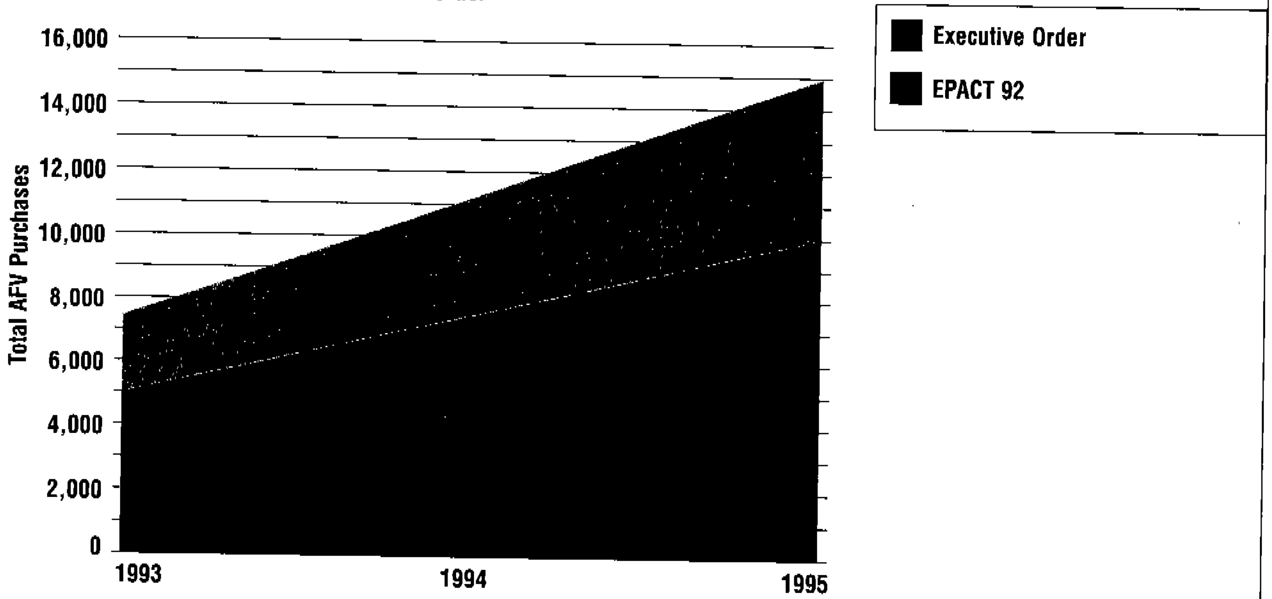
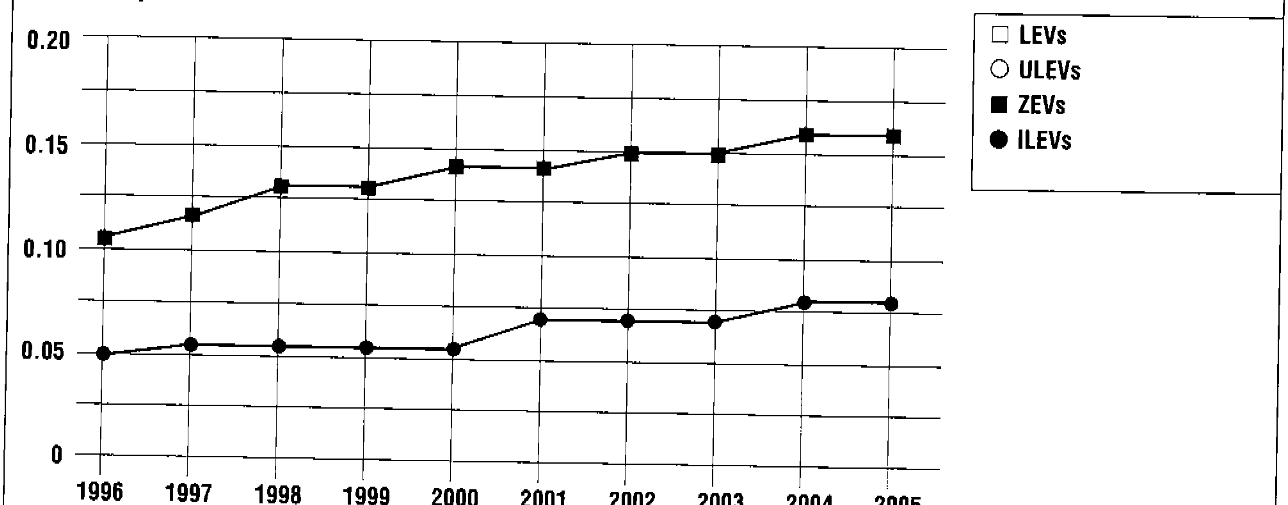


Figure 2

NO_x Benefits of CFFV Program with 10,000 Vehicles and "Appropriate" I/M

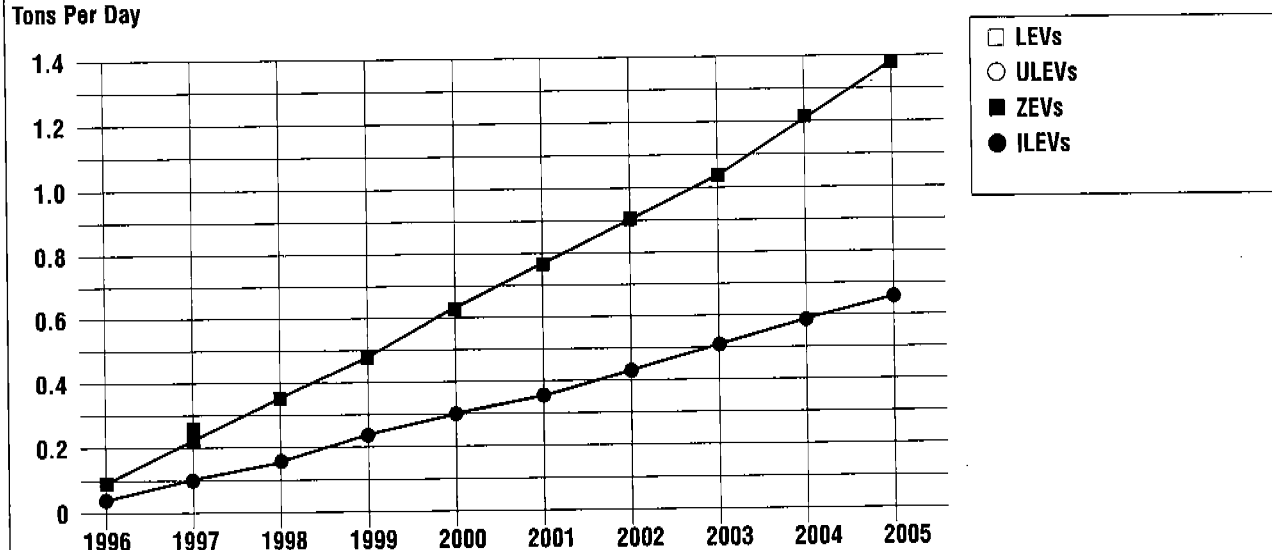
Tons Per Day



	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
LEVs	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08
ULEVs	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08
ZEVs	0.11	0.12	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16
ILEVs	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08

Figure 3

NO_x Benefits of CFFV Program with 10,000 Vehicles Per Year and "Appropriate" I/M

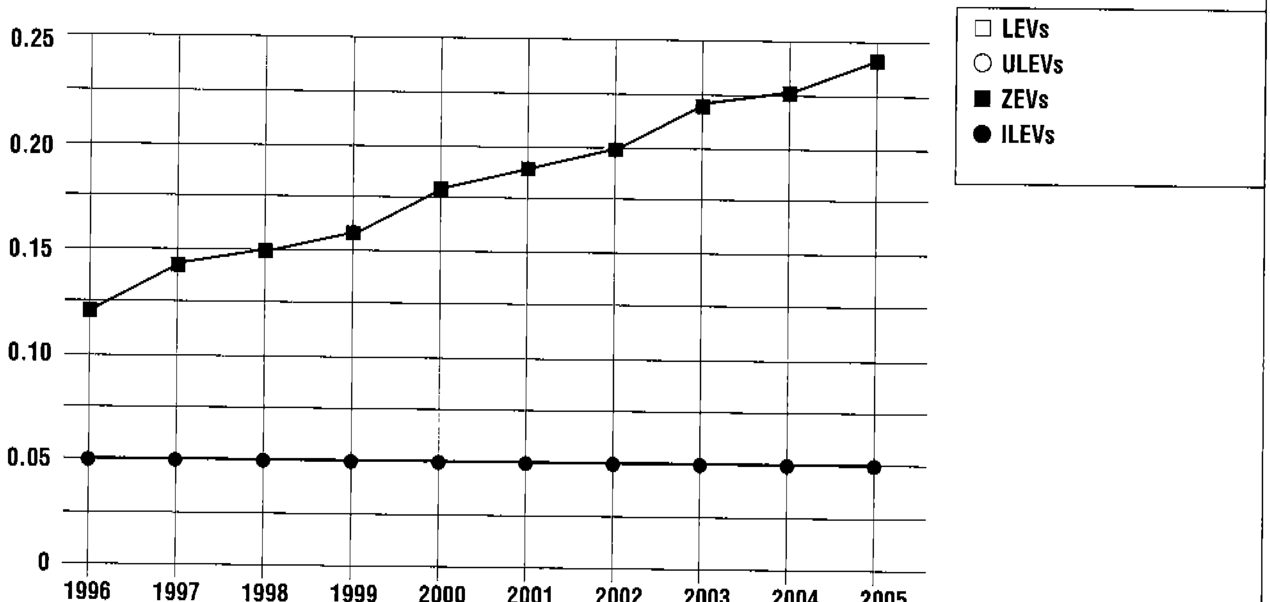


1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	
0.05	0.11	0.17	0.23	0.30	0.36	0.43	0.51	0.58	0.66	LEVs
0.05	0.11	0.17	0.23	0.30	0.36	0.43	0.51	0.58	0.66	ULEVs
0.11	0.24	0.36	0.49	0.63	0.77	0.92	1.07	1.23	1.39	ZEVs
0.05	0.11	0.17	0.23	0.30	0.36	0.43	0.51	0.58	0.66	ILEVs

Figure 4

NO_x Benefits of CFFV Program with 10,000 Vehicles and Enhanced I/M

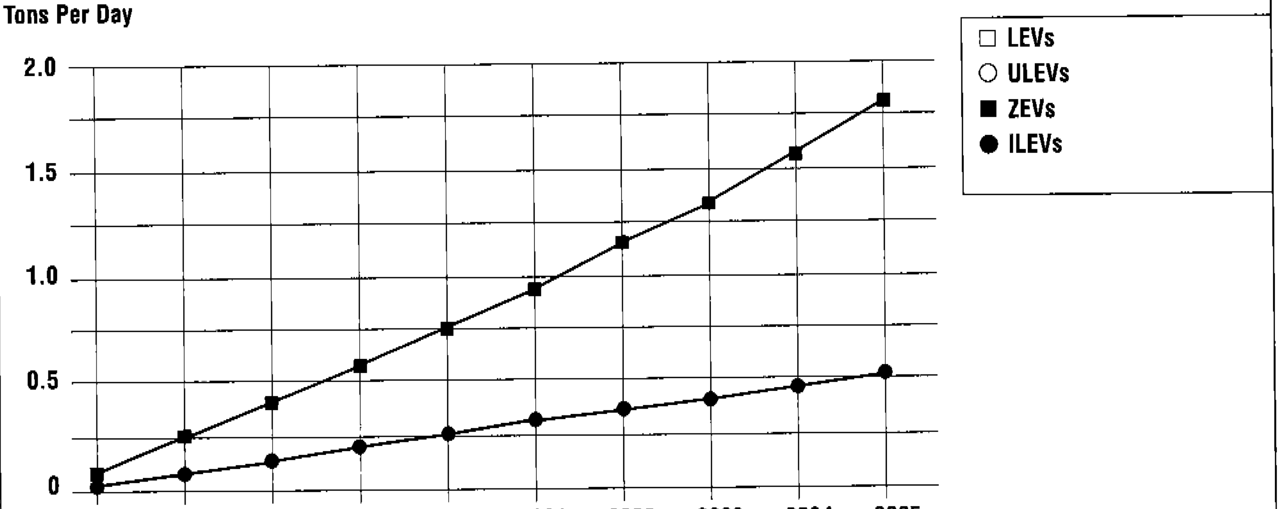
Tons Per Day



	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
LEVs	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
ULEVs	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
ZEVs	0.12	0.14	0.15	0.16	0.18	0.19	0.20	0.22	0.23	0.24
ILEVs	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05

Figure 5

NO_x Benefits of CFFV Program with 10,000 Vehicles Per Year and Enhanced I/M



1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	
0.05	0.10	0.15	0.21	0.26	0.31	0.36	0.41	0.46	0.52	LEVs
0.05	0.10	0.15	0.21	0.26	0.31	0.36	0.41	0.46	0.52	ULEVs
0.12	0.26	0.41	0.57	0.75	0.94	1.14	1.35	1.58	1.82	ZEVs
0.05	0.10	0.15	0.21	0.26	0.31	0.36	0.41	0.46	0.52	ILEVs

Table 1

Statutory Vehicle Purchase Requirement Phase-In Rate

Vehicle Class	Model Year 1998	Model Year 1999	Model Year 2000
LDVs/LDTs	30%	50%	70%
HDVs	50%	50%	50%

Source: Clean Air Act Amendments of 1990.

Table 2

Areas and States Affected by the Clean-Fuel Fleet Program

Affected Area:	Affected State(s):
1. Atlanta	Georgia
2. Baltimore	Maryland
3. Baton Rouge	Louisiana
4. Beaumont-Port Arthur	Texas
5. Boston-Lawrence-Worcester (Eastern Massachusetts)	Massachusetts, New Hampshire
6. Chicago-Gary-Lake County	Illinois, Indiana
7. Denver-Boulder	Colorado
8. El Paso	Texas
9. Greater Connecticut	Connecticut
10. Houston-Galveston-Brazoria	Texas
11. Los Angeles-South Coast Air Basin	California
12. Milwaukee-Racine	Wisconsin
13. New York-Northern New Jersey-Long Island	Connecticut, New Jersey, New York
14. Philadelphia-Wilmington-Trenton	Delaware, Maryland, New Jersey, Pennsylvania
15. Providence (All Rhode Island)	Rhode Island
16. Sacramento	California
17. San Diego	California
18. San Joaquin Valley	California
19. Southeastern Desert Modified Air Quality Management District	California
20. Springfield (Western Massachusetts)	Massachusetts
21. Ventura County	California
22. Washington, DC	Maryland, Virginia, District of Columbia

Source: EPA.

Table 3

Projected CFFVs In Use

Area	2000	2005	2010
Atlanta, GA	5,029	47,445	53,908
Baltimore, MD	3,576	33,739	38,335
Baton Rouge, LA	819	7,732	8,785
Beaumont-Port Arthur, TX	670	6,326	7,188
Boston-Lawrence-Worcester, MA, NH	5,811	54,825	62,294
Chicago-Gary-Lake County, IL, IN, WI	11,212	105,784	120,196
Denver-Boulder, CO	2,943	27,764	31,546
El Paso, TX	1,006	9,489	10,782
Greater Connecticut	2,645	24,952	28,352
Houston-Galveston-Brazoria, TX	6,444	60,800	69,083
Los Angeles-South Coast Air Basin, CA and Ventura County, CA	21,195	199,971	227,214
Milwaukee-Racine, WI	2,198	20,735	23,560
New York-Northern New Jersey-Long Island	22,946	216,489	245,982
Philadelphia-Wilmington-Trenton, PA, NJ, DE, MD	8,120	76,615	87,052
Providence (All Rhode Island)	1,490	14,058	15,973
Sacramento, CA	2,086	19,681	22,362
San Diego, CA	3,576	33,739	38,335
San Joaquin Valley, CA	931	8,786	9,983
Southeast Desert Modified Air Quality Management District, CA	782	7,380	8,386
Springfield, MA	708	6,677	7,587
Washington, DC, MD, VA	5,513	52,014	59,099
Total	109,700	1,035,000	1,176,000

Source: EPA, June 19, 1991.

Table 4

Light-Duty ILEV Exhaust Emission Standards (gpm)

Vehicles/Engine Class/Subclass Miles	NMOG	CO	NO_x	PM	HCHO
Light-Duty Vehicles					
50,000	0.075	3.4	0.2	—	0.015
100,000	0.090	4.2	0.3	0.08	0.018
LDTs, 0-6000 lbs GVWR, 0-3750 lbs Loaded Vehicle Weight (LVW)					
50,000	0.075	3.4	0.2	—	0.015
100,000	0.090	4.2	0.3	0.08	0.018
LDTs, 0-6000 lbs GVWR, 3751-5750 lbs LVW					
50,000	0.100	4.4	0.4	—	0.018
100,000	0.130	5.5	0.5	0.08	0.023
LDTs, over 6000 lbs GVWR, 0-3750 lbs TW					
50,000	0.125	3.4	0.2	—	0.015
120,000	0.180	5.0	0.3	0.08	0.022
LDTs, over 6000 lbs GVWR, 3751-5750 lbs TW					
50,000	0.160	4.4	0.4	—	0.018
120,000	0.230	6.4	0.5	0.10	0.027
LDTs, over 6000 lbs GVWR, 5751-8500 lbs TW					
50,000	0.195	5.0	0.6	—	0.022
120,000	0.280	7.3	0.8	0.12	0.032

Source: EPA.

Table 5

Proposed ULEV Standards for Clean-Fuel Fleet Heavy-Duty Engines

$NMHC+NO_x$ (g/bhp-hr)	CO (g/bhp-hr)	Particulate (g/bhp-hr)	HCHO (g/bhp-hr)
2.5	7.2	0.05	0.05

Source: EPA.

Table 6

ZEV Emission Factors

	Efficiency Rating (kilowatt-hours/mile)			
Emission	.35 (Year 2000)	.24 (Year 2005)	.24 (Year 2010)	.24 (Year 2015)
VOC (gpm)	0.005	0.003	0.003	0.003
NO_x (gpm)	0.15	0.11	0.14	0.14
CO (gpm)	0.06	0.04	0.04	0.04
SO_2 (gpm)	1.35	0.60	0.37	0.37

Source: Northeast States for Coordinated Air Use Management.

Table 7

States that Have Submitted Committal Opt-Out SIPs

State	Proposed Alternative to CFF Program[1]
California	CA LEV Program
Connecticut	Considering CA LEV Program
Delaware	Undetermined (Committal SIP submitted after November 1992 deadline)
Maryland	Possibly CA LEV Program
Massachusetts	CA LEV Program
New Hampshire	Possibly CA LEV Program, intensified enhanced I/M, reformulated gasoline program and/or a substitute fleet program (see description of state's ILEV program)
New Jersey	Undetermined
New York	CA LEV Program
Rhode Island	Possibly CA LEV Program and reformulated gasoline program
Texas	Substitute fleet program (see description of Texas Alternative Fuel Fleet Program)
Virginia	Possibly CA LEV Program and the Energy Policy Act of 1992

Source: EPA.

[1]*As identified in states' November 1992 committal SIPs.*

Nonroad Vehicles and Engines

DESCRIPTION OF THE SOURCE

EPA estimates that on a typical summer day, nationally, nonroad vehicles and engines are responsible for about 34 percent of the mobile source NO_X emissions, as illustrated in *Table 1*. Within the category of nonroad vehicles and engines there are a wide variety of sources, as shown in *Table 2*.

AVAILABLE CONTROL STRATEGIES

Diesel-Powered Engines 50 HP and Above. Diesel-powered engines above 50 HP are by far the most significant source category of NO_X emissions from nonroad sources. Indeed, EPA estimates that this category constitutes about 75 percent of the nonroad engine and vehicle NO_X emission inventory and about 9 percent of the entire NO_X emission inventory. Consequently, EPA elected to regulate this source category of nonroad engines first and, on May 17, 1993 (58 *Federal Register* 28809), proposed emission standards for compression-ignition (diesel-cycle) engines 50 hp and above. On May 27, 1994 EPA finalized the regulations, expressing the standards in grams per kilowatt-hour (g/kW-hr). These regulations were published in the *Federal Register* on June 17, 1994 (59 *Federal Register* 31306).

For nonroad compression-ignition engines at or above 37 kilowatts (50 hp), EPA has set a NO_X standard of 9.2 g/kW-hr (6.9 g/bhp-hr). The agency has also established hydrocarbon, CO, particulate and smoke standards. The NO_X standard will be phased in beginning in 1996, depending on gross maximum power output category, as shown in *Table 3*. Emissions averaging, banking and trading are allowed. EPA has noted that the technologies necessary to meet the NO_X standards, which involve engine modifications, have already been proven effective for on-highway engines.

In 1992, California adopted emission standards for 1996 and later model year heavy-duty nonroad diesel engines. CARB adopted the same 6.9-g/bhp-hr NO_X standard set by EPA for 1996, but included a Phase II NO_X standard of 5.8 g/bhp-hr for engines in the 175-750 hp category.

Small Nonroad Engines. While small engines constitute a significant source of VOC emissions, EPA estimates that this category of engines contributes relatively little to the NO_X emission inventory. For example, lawn and garden equipment contributes less than 1 percent of the nonroad NO_X emission inventory and EPA estimates that diesel engines under 50 hp make up approximately 3 percent of the nonroad NO_X emission inventory.

California has adopted two-phase regulations for small utility and lawn and garden equipment powered by gasoline or diesel engines under 25 hp, as shown in *Table 4*. These standards, which take effect January 1, 1995, are designed primarily to target VOC emissions reductions; California has estimated, for example, that the Phase I standards would have little effect on NO_X emissions and, in fact, the state expects a slight increase in NO_X emissions from two-stroke engines.

On May 16, 1994 (59 *Federal Register* 25399), EPA proposed Phase I emission standards for new nonroad spark-ignition engines at or below 19 kilowatts (25 horsepower). The standards, which appear in *Table 5*, are based on the California Phase I utility engine standards and would take effect August 1, 1996. EPA expects the proposed standards to result in a 32-percent reduction in hydrocarbon emissions and a 14-percent reduction in CO emissions from these engines by the year 2020, when complete fleet turnover is projected. As a result of the regulations, EPA expects that NO_X emissions will increase on average about 1.36-fold or 34,000 tons per year. EPA believes these NO_X increases would increase the national NO_X inventory by about one quarter of 1 percent. EPA is developing a proposal for Phase II standards through a negotiated rulemaking process. The proposal is expected to be issued in 1996, but the effective date for the Phase II standards and the NO_X control requirements have yet to be identified.

EPA is also developing regulations for recreational marine engines. These regulations are expected to result in significant long-term VOC reductions. However, as in the case of the Phase I standards for small spark-ignition engines, EPA anticipates that NO_X emissions from recreational marine engines will also increase.

Locomotives. EPA estimates that diesel-powered locomotives contribute slightly more than 6 percent of the nonroad engine NO_X inventory and about 2.5 percent of the motor vehicle NO_X inventory. A contractor for CARB has estimated that emissions from locomotives are more than double the 5.0-g/bhp-hr NO_X standard applicable to on-road heavy-duty engines, as shown in *Table 6*.

Under Section 222 of the CAAA, EPA is required to establish by November 15, 1995 emission standards for locomotives. While EPA is still almost six months away from proposing these emission standards, the preamble to the proposed California FIP provides insight into the types of controls EPA is contemplating.

EPA currently plans to propose that "freshly manufactured," or new, locomotives and locomotive engines built between January 1, 2000 and December 31, 2004 be required to meet a NO_X emission standard of 7.0 g/bhp-hr; the agency is studying the possibility of proposing a NO_X standard as low as 5.0 g/bhp-hr. For new locomotives and locomotive engines manufactured after January 1, 2005, EPA plans to propose a 6.0-g/bhp-hr NO_X standard and is considering proposing a NO_X standard as low as 4.0 g/bhp-hr. EPA estimates that the Phase I standards would reduce NO_X emission levels by 42 to 48 percent and the Phase II standards would reduce NO_X by 61 to 65 percent over uncontrolled levels.

Locomotive engines are used for extended periods — up to 30 to 40 years or more. These engines are rebuilt approximately every six years. For rebuilt locomotive engines EPA is considering two options. Option I would be nationwide rebuilt engine emission performance requirements and Option II would apply those requirements only to California. EPA is proposing a NO_X emission standard of 8.0 g/bhp-hr for rebuilt locomotive engines that were originally manufactured prior to January 2000.

California has been developing rules governing in-use emissions from diesel-powered locomotives; the state is preempted by the CAAA from establishing emission standards for new locomotives. California is contemplating a strategy that would require the railroad industry to achieve statewide emissions reductions. For NO_X, California is considering up to an 80-percent railroad industry-wide NO_X reduction (see *Table 7*). To achieve these reductions the railroad industry could utilize a mix of strategies, including changes in operating practices, converting to alternative fuels or electrification, engine modifications and exhaust after-treatment controls. *Table 8* provides a summary of strategies identified by CARB.

Commercial Marine Vessels. EPA estimates that marine vessels contribute approximately 12 percent of the nonroad NO_X emission inventory. Marine engine NO_X emission factors, published by EPA, are based on data that are approximately 15 to 20 years old. The NO_X emission factor for marine diesel engines is listed by EPA as 300 lbs per 1000 gallons of fuel. CARB suggests recent fuel efficiency improvements in large low-speed diesel engines and the trend toward poorer quality fuel have increased the amount of NO_X produced per unit of fuel burned. More recent information cited by CARB indicates the range of NO_X emissions for marine diesel engines is 650 to 1200 parts per million corrected to 15-percent oxygen. This NO_X emission range corresponds to approximately 8 to 15 grams of NO_X per horsepower-hour or 360 to 670 pounds of NO_X per 1000 gallons of fuel burned.

STAPPA/ALAPCO
Recommendation

▶ Many strategies that have been used or considered to control emissions from other mobile sources could be applicable to nonroad equipment. While the nonroad category includes a broad array of engines and equipment, a small subset is responsible for the majority of emissions associated with these sources. For example, construction equipment represents, on average, approximately one-half of nonroad NO_X emissions. EPA has published rules regulating 50-horsepower and above nonroad diesel engines, which will serve as the primary control strategy for nonroad NO_X emissions. Agencies seeking additional near-term NO_X reductions could explore programs including, among others, scrappage and other incentives to increase the turnover of these sources.

California has been developing a control strategy for commercial marine vessels for several years. CARB is scheduled to review its progress in developing a control program in the Fall of 1994.

CARB is considering working with coastal local air pollution control districts to develop uniform New Source Review and existing source permit provisions for marine vessels. These provisions would require that stationary sources include in their permit any marine vessel emissions associated with loading or unloading at such facilities and emissions from such vessels while operating in the district's California Coastal Waters (CCWs). In addition to the above provisions, all marine vessels visiting permitted facilities could be required to use engines that meet all CARB certification requirements for new and in-use marine vessels operating in CCWs. Vessel emissions estimates would be included when determining the permitting facility's total emissions. As an alternative to imposing emission limits on a per-vessel basis, California is also considering market-based approaches that would combine emissions averaging with marketable emission permits.

Emissions could be reduced from changes in operations, engine modifications and exhaust after-treatment. In a 1991 staff report, CARB identified three such strategies that are listed in *Table 9*. In that report, CARB suggested emission limits for new and existing marine engines, as shown in *Tables 10 and 11*.

EPA has not yet initiated rulemaking activity covering commercial marine vessels. Again, provisions in the California FIP may provide insight into future EPA rulemakings. EPA is proposing a three-tier emission fee structure based on a price of $10,000 per ton of NO_X emissions emitted into the atmosphere. EPA anticipates that vessel operators could reduce the amount of fees charged by employing such strategies as 1) using onshore power sources instead of internally generated power while they are in port (called "cold ironing"), 2) relocating shipping channels and 3) using low-emitting diesel engines. For cost and convenience reasons, EPA favors this approach over imposing per-vessel emission limits.

POTENTIAL NATIONAL EMISSIONS REDUCTION

Compression Ignition Engines At or Above 37kW (50 hp). In its final rulemaking, EPA estimates that the new NO_X standards should reduce average per-unit emissions from large off-road engines by 27 percent before the year 2010, with a 37-percent reduction once a complete fleet turnover occurs or by the year 2025. EPA anticipates this will result in annual nationwide reductions of approximately 800,000 tons of NO_X by the year 2010 and over 1,200,000 tons of NO_X by the year 2025. These projected emissions reductions would represent nearly a 4-percent total nationwide annual reduction in NO_X emissions in 2010. *Table 12* identifies the EPA-estimated per-source NO_X emissions reductions expected and *Table 13* lists the projected annual nationwide NO_X emissions reductions.

CARB estimates that its NO_X standards will result in a 56-percent reduction in NO_X emissions from engines in this category in the year 2010.

Locomotives. Assessment of the potential emissions reductions from locomotives is still in the preliminary stages. EPA estimates that the reduction in locomotive NO_X emissions resulting from new locomotives meeting the proposed standards would be approximately 5 to 7 percent in 2005 and 11 to 14 percent in 2010. EPA calculates that the combined new and rebuilt locomotive emission limits would result in a reduction in NO_X emissions from locomotives of about 35 to 43 percent in 2005 and 38 to 46 percent in 2010. The potential emissions reductions calculated by CARB under the industry-wide NO_X reduction strategy that is being considered are shown in *Table 7*.

Marine Vessels. In developing its proposed rule for marine vessels, California has estimated that NO_x emissions from new engines could be reduced by up to 50 to 89 percent and existing engines by up to 30 to 80 percent, depending on the type of engine (see *Tables 10 and 11*). EPA anticipates that the ship and port fees program it is proposing for applicable local air districts in California will achieve, for example, a 30-percent NO_x reduction in the South Coast Air Quality Management District.

Costs and Cost Effectiveness

EPA estimates that the average per-engine cost of complying with its proposed NO_x standards for nonroad diesel engines 50 hp and above will be approximately \$110 and no fuel economy penalty is expected to occur. EPA calculates the cost effectiveness of this proposed rule to be \$86 per ton of NO_x removed. CARB calculated the cost effectiveness of its Phase II NO_x standards at approximately \$1160 per ton of NO_x removed.

Estimates of the cost effectiveness of controlling NO_x emissions from locomotives and marine vessels are still very preliminary. *Table 8* identifies the preliminary CARB cost estimates for locomotives. In developing its rule for marine vessels, CARB estimated that the cost effectiveness of possible control strategies would range from \$0.11 to \$2.11 per pound of NO_x removed with water/fuel emulsion, to \$0.20 to \$9 per pound of NO_x reduced if SCR were used. The higher end of these cost effectiveness ranges represent vessels with a low frequency of visits to California coastal waters.

Federal Rulemaking and/or Guidance Documents

On February 15, 1994, EPA proposed the California FIP, which contains provisions related to several categories of nonroad engines. On May 16, 1994, EPA proposed emissions standards for spark-ignition nonroad engines at or below 19 kilowatts (25 horsepower). On June 17, 1994, EPA published emission standards for nonroad diesel-cycle compression-ignition engines at or above 37 kilowatts.

References

1. U.S. Environmental Protection Agency. June 17, 1994. *Determination of Significance for Nonroad Sources and Emission Standards for New Nonroad Compression-Ignition Engines At or Above 37 Kilowatts.* Final Rule. (59 *Federal Register* 31306).

2. U.S. Environmental Protection Agency. May 16, 1994. *Proposed Emission Standards for New Nonroad Spark-Ignition Engines At or Below 19 Kilowatts.* (59 *Federal Register* 25399).

3. U.S. Environmental Protection Agency. February 14, 1994. *Proposed State Implementation Plan for Sacramento, Ventura, and South Coast Areas of California.*

4. U.S. Environmental Protection Agency. May 17, 1993. *Proposed Rule on Control of Emissions of Oxides of Nitrogen and Smoke from New Nonroad Compression-Ignition Engines At or Above 50 Horsepower.* (58 *Federal Register* 28809).

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6. California Air Resources Board. November 22, 1991. *Staff Report on Regulations Regarding the California Exhaust Emission Standards and Test Procedures for New 1996 and Later Heavy-Duty Off-Road Dual-Cycle Engines and Equipment Engines.*

7. California Air Resources Board. October 22, 1990. *Staff Report on Exhaust Emission Standards and Test Procedures for 1994 and Subsequent Model Year Utility and Lawn and Garden Equipment Engines.*

8. California Air Resources Board. November 18, 1993. *Report to the Legislature on Emission Regulations from Locomotives Operating in California.*

9. Engine, Fuel, and Emission Engineering, Inc. October 13, 1993. *Controlling Locomotive Emissions in California: Technology, Cost-Effectiveness, and Regulatory Strategy.* Preliminary Draft.

10. California Air Resources Board. October 10, 1991. *Staff Report on a Plan for the Control of Emissions from Marine Vessels.*

Table 1

Emissions from Various Sources

Source	NO_x (tpsd)
Nonroad Engines and Vehicles	9,724-10,892
Heavy-Duty Gasoline Highway Vehicles	888
Heavy-Duty Diesel Highway Vehicles	647
Light-Duty Vehicles	7,852
Light-Duty Trucks	3,346

Source: EPA.

Table 2

National Emissions Summary of Nonroad Vehicles and Engines (relative percentage contribution per summer day)

Equipment Category	NO_x
Lawn and Garden	0.93
Airport Service	2.62
Recreational	0.10
Recreational Marine	5.02
Light Commercial	0.94
Industrial	5.99
Construction	39.26
Agricultural	37.67
Logging	1.96
Marine Vessels	5.50

Source: EPA.

Table 3

Certification Effective Dates[1]

Implementation Date	Engine Size (kW [hp])
January 1, 1996	≥130 to ≤560 [≥175 to ≤750]
January 1, 1997	≥75 to <130 [≥100 to <175]
January 1, 1998	≥37 to <75 [≥50 to <100]
January 1, 2000	>560 [>750]

Source: EPA.

[1]*Optional early certification is allowed one year prior to the applicable effective date for engines participating in the averaging, banking and trading program.*

Table 4

California Emission Standards for Utility Engines

Non-Handheld Equipment Year	Displacement	HC and NO_x (g/bhp-hr)	CO (g/bhp-hr)	PM (g/bhp-hr)
1995-98	less than 225 cc	12.0	300	0.9
(Phase I)	225 cc and greater	10.0	300	0.9
1999 and Later (Phase II)	all	3.2	100	0.25

Handheld Equipment Year	Displacement	HC and NO_x (g/bhp-hr)	CO (g/bhp-hr)	PM (g/bhp-hr)
1995-98	less than 20cc	220	600	4.0
(Phase I)	20cc to less than 50 cc	180	600	4.0
	50 cc and greater	120	300	4.0
1999 and Later (Phase II)	all	50	130	0.25

Source: California Air Resources Board.

Table 5

EPA Proposed Phase I Emission Standards for Spark-Ignition Nonroad Engines at or Below 19 Kilowatts (grams per kilowatt hour)

Engine Class	HC+NO_x	HC	CO	NO_x
I	16.1	—	402	—
II	13.4	—	402	—
III	—	295	805	5.36
IV	—	241	805	5.36
V	—	161	402	5.36

Class I: Non-handheld engines less than 225 cc in displacement.

Class II: Non-handheld engines greater than or equal to 225 cc in displacement.

Class III: Handheld engines less than 20 cc in displacement.

Class IV: Handheld engines equal to or greater than 20 cc and less than 50 cc in displacement.

Class V: Handheld engines equal to or greater than 50 cc in displacement.

Source: EPA.

Table 6

Locomotive Emissions Compared to U.S. Federal and California Emission Standards for Heavy-Duty Vehicle Engines

	HDE Emissions of NO_x (g/bhp-hr)
1991 Federal/Calif.	5.0
1994 Federal (1993 Bus)	5.0
1994 Bus	5.0
1994 California	5.0
1996 California Off-Road	6.9
	Locomotive Emissions of NO_x (g/bhp-hr)
EMD 12-645E3B	11.7
EMD 12-710G3A	11.6
GE 12-7FDL	10.7

Source: Engine, Fuel, Emissions Engineering, Inc.

Table 7

Industry-Wide Emission Phasedown Schedule for Locomotives Being Considered by CARB

Year	NO_x
1996	10%
1997	20%
1998	30%
1999	40%
2000	50%
2001	60%
2002	70%
2003	80%
2004-10	80%

Source: California Air Resources Board.

Table 8

Possible Control Technological Combinations for NO_x Reductions from Railroad Engines

Options	NO_x Reduced	1987 Statewide Emissions (tpd)	Cost[1] ($/yr)	Cost Effectiveness ($/lb)
LNG[2] Dual-Fuel	70%	112	35M	0.45
LNG Dual-Fuel Line Haul LNG SI Local/Switch	80%	128	42M	0.45
LNG SI	86%	138	70M	0.70
LNG Dual-Fuel Line Haul	72%	115	71M	0.85
Remanufacture/Replace Local/Switch LNG+SCR	97%	155	109M	0.95
SCR	90%	144	154M	1.45
Engine Modifications	38%	61	70M	1.60
Low Aromatic Diesel Fuel	10%	16	29M	2.50
Electric Line Haul, LNG+SCR Local/Switch[3]	99%	159	858M	7.40

Source: California Air Resources Board.

[1]These costs are for a California fleet with an assumed composition of line haul, local and switch yard locomotives. These costs include those required for the purchase and maintenance of additional locomotives required by a potential California-only fleet, where appropriate.

[2]LNG = Liquified Natural Gas

[3]The contractor's numbers do not include power plant emissions. Estimates of such emissions are being developed.

Table 9

Possible Control Strategies for Marine Vessels

Control Strategy	NO_x Emission Reduction
Injection Timing Retard (4°)	up to 40%
Water/Fuel Emulsion	up to 35%
Selective Catalytic Reduction	70 to 90%

Source: California Air Resources Board.

Table 10

Suggested Emission Levels for New Marine Engines

Power Plant	Application	Load	Baseline NO_x Rates (ppm)	Proposed NO_x Rates (ppm)	Percent Reduction
Diesel-Cycle	Ocean-Going	≥ 25% of Max.	750-1200	130	78-89
		< 25% of Max.	—	450	—
Steam Turbines	Ocean-Going	—	120	80	33
Gas Turbines	Ocean-Going	—	90-220	42	53-81
Diesel-Cycle	Other[1]	—	600-1200	600	0-50
Gas Turbines	Other	—	90-220	42	53-81

Source: California Air Resources Board.

[1]Other applications include both the on-board ship engines for non-ocean-going vessels and any auxiliary engines for all ships.

Table 11

Suggested Emission Levels for In-Use Marine Engines

Power Plant	Application	(ppm)	Baseline NO_x Rates (ppm)	Proposed NO_x Limit Percent Reduction
Diesel-Cycle	Ocean-Going	600-1680	600	0-64
Steam Turbines	Ocean-Going	120	80	33
Gas Turbines	Ocean-Going	90-220	42	53-81
Diesel-Cycle	Other[1]	650-1200	750	0-38

Source: California Air Resources Board.

[1]Other applications include both the on-board ship engines for non-ocean-going vessels and any auxiliary engines for all ships.

Table 12

Compression-Ignition Engines Above 50 HP Estimated Annual Per-Source NO_x Emissions

	Average Per-Source NOx (tpy)
Baseline (no control)	0.49
Controlled (6.9 g/bhp-hr or 9.2 g/kW-hr)	0.31

Source: EPA.

Table 13

Compression Ignition Engines Above 50 HP-Projected Annual Nationwide NO_x Emissions (tons/year)

Year	Baseline	With Proposed Controls	Reduction From Baseline	Percent of Baseline
1990	2,120,000	2,120,000	—	—
1996	2,190,000	2,180,000	10,000	0.05
2000	2,300,000	2,090,000	210,000	9
2005	2,490,000	1,980,000	510,000	20
2010	2,740,000	1,950,000	790,000	27
2015	3,030,000	2,010,000	1,020,000	34
2020	3,350,000	2,140,000	1,210,000	36
2025	3,690,000	2,330,000	1,360,000	37

Source: EPA.

Transportation Control Measures

Description of Control Measure

Reductions in emissions of nitrogen oxides required to satisfy reasonable further progress (RFP) targets for 1996 and beyond will depend heavily upon achieving reductions of in-use vehicle emissions. In addition to complying with the RFP requirements of the CAAA, the importance of achieving reductions in in-use vehicle emissions is also highlighted by separate CAAA provisions, including those in Section 182(d)(1), calling for the adoption of an interim SIP revision by 1992 to offset emissions increases expected to result from growth in vehicle miles traveled (VMT) and those requiring an interim conformity test, which calls upon transportation planning agencies to adopt plans that achieve an "annual emission reduction" of in-use vehicle emissions.

Both the CAAA and the Intermodal Surface Transportation Efficiency Act of 1991 specifically require that VMT growth be addressed in the transportation planning process. For ozone nonattainment areas designated as Serious, Severe and Extreme, states must verify every three years that current VMT is consistent with the VMT projections used in the SIP. When necessary, states must revise SIPs to achieve adjusted VMT/emissions reduction targets. Severe and Extreme nonattainment areas are required by the CAAA to adopt and enforce transportation control measures (TCMs) sufficient to offset emissions associated with VMT growth.

Available Control Strategies

Table 1 summarizes the results of three efforts to identify TCMs that are currently in use and have demonstrated effectiveness in reducing travel demand (i.e., reducing the number of trips or trip lengths) or contributing to mode shifts from the single-occupancy vehicle (SOV) to ride-sharing, public transit and other forms of shared-ride services, bicycles or walking. These documents include: 1) the U.S. Environmental Protection Agency's *Transportation Control Measure Information Documents* (March 1992), which address the TCMs identified in Section 108(f) of the CAAA; 2) *Cost and Effectiveness of Transportation Control Measures: A Review and Analysis of the Literature* (April 1993), a draft report prepared by Apogee Research, Inc., for the National Association of Regional Council's (NARC's) Clean Air Project, that reviews the VMT-reduction potential of various strategies; and 3) *Motor Vehicle Use and the Clean*

Air Act: Boosting Efficiency by Reducing Travel (July 1993), a review of the VMT-reduction potential of transportation strategies conducted by Michael Replogle of the Environmental Defense Fund (EDF).

EPA's TCM information documents, prepared to comply with a requirement of the CAAA, only quantitatively assess the VMT impacts and the emissions-reduction potential of the measures addressed.

The Apogee/NARC assessment of TCMs considers VMT-reduction potential based upon a review of the literature and the application of planning judgment. This document recognizes that the effectiveness of TCMs varies depending on the circumstances. It does not specifically identify the time period within which the estimated VMT reductions are expected to occur.

The EDF analysis is the most comprehensive with regard both to the number of TCMs considered and the time period for implementation of listed measures. EDF also recognizes that the effectiveness of given TCMs varies depending on circumstances; however, unlike the others, EDF compares the effectiveness of TCMs over various time periods. For example, EDF identifies a number of TCMs that are considered not to be available by 1996, largely because of lead times needed for implementation, but which are identified as potentially effective strategies for 2000 and beyond.

Although the Apogee/NARC and EDF assessments of the VMT-reduction potential identified for each listed TCM have not been independently reviewed for the purposes of this document, the conclusions of their respective reports are summarized here to provide an indication of the range of estimated reductions.

Potential National Emissions Reduction

It is important to note that it is not appropriate to quantitatively estimate the effectiveness of any particular TCM without considering the specific context in which the TCM will be implemented. As both Apogee/NARC and EDF acknowledge, the effectiveness of a TCM may vary significantly from one nonattainment area to another depending on circumstances. A summary of the key variables that can substantially affect the effectiveness of any given TCM follows.

Existing Transportation System. The effectiveness of any given TCM or group of TCMs depends heavily upon the nature of the existing transportation system in a nonattainment area. For example, the addition of certain TCMs (such as land use policies designed to direct new development into corridors served by rail transit or enhanced bike/pedestrian access to transit) in an area heavily served by transit (e.g., New York City, where 40 percent of commuting trips are by transit) would have significantly different effects on VMT than the same measures adopted in an area without a well-developed transit system. Therefore, the characteristics of the transportation system to which a TCM is proposed to be added must be considered in evaluating the effectiveness of the measure.

STAPPA/ALAPCO
Recommendation

▶ State and local agencies should evaluate the potential effectiveness of TCMs given their particular needs and circumstances, with a special emphasis on pricing strategies, which offer the greatest potential for emission reductions. These strategies could include, among others, parking management, traffic flow improvements and road pricing.

Synergistic Effects of TCMs. TCMs taken in isolation tend to have minimal benefits compared to integrating numerous, related TCMs. In addition, TCMs that reduce total VMT will be more effective in reducing NO_x than will strategies that shift traffic from one time to another or one road to another. For example, pricing strategies are designed to increase the cost of driving alone compared to the cost of alternative modes. Therefore, if only one pricing measure is adopted, such as congestion pricing on major regional highways, the benefits may be minimal because the public response may be to choose unpriced alternate routes, as opposed to abandoning their SOVs. However, if regional parking pricing is added to congestion pricing, the incentive to leave the personal auto at home and use an alternative mode is enhanced.

Even greater benefits are achieved if the revenues generated by pricing measures are used to increase the supply of alternative modes (e.g., adding bus routes to provide more convenient service in more areas, reducing waiting times by adding more service to existing routes or adding dial-a-ride door-to-door service to the existing system), in which case the convenience and speed of alternative modes can be improved as the cost of the SOV is increased. Whereas, if transit service were enhanced without changing the relative price of driving an SOV compared to the transit alternatives, little increased ridership would be expected. Benefits in terms of improved mobility and better air quality from such an integrated approach are far greater than the benefits of implementing only one such measure.

Since the success of TCM strategies depends upon the setting in which they are applied, the most effective TCM strategy will combine TCM disincentives, including programs to cash out parking subsidies, Employee Commute Options and congestion pricing, with TCM incentives, such as ridesharing services, HOV lanes, intermodal transfers and connections and park-and-ride facilities. Such combinations of measures will be more successful at promoting changes in mode choice, by providing drivers with options for substituting a less polluting mode for their SOV trip.

In recognition of the synergistic effects of multiple strategies, the lists of TCMs presented in *Tables 1 and 2* group TCMs into sets of strategies that are closely related in concept and that are likely to be more effective if considered as a package.

Comprehensiveness of a Strategy. TCMs applied only to limited parts of a nonattainment area or only to certain corridors will be less effective than measures applied throughout a nonattainment area. For example, a pricing strategy applied only to parking in a central business district will have a significantly lower impact on regional emissions than a regional parking strategy. Similarly, adding a high-occupancy vehicle (HOV) lane to one limited-access corridor in a nonattainment area will have an impact on those who drive that corridor, but will have a much more limited impact than if an HOV network is built to connect all the limited access links in the regional highway system. Land use policies that encourage higher-density development in transit corridors in one part of the nonattainment area can have an effect on mode split in that corridor, but the regional emissions reduction benefits are much greater if similar policies are applied to all transit corridors in a metropolitan area.

In view of these and other variables, it is not possible to predict in advance the quantitative benefits that may result from the adoption of any given mix of the listed TCMs in a specific nonattainment area. *Tables 1 and 2* have not been endorsed by EPA; however, the estimated reductions in VMT identified in these tables are useful for comparing the relative effectiveness of TCMs in any area. They are also useful for the purposes of making first-order estimates of the kinds of measures that may be necessary to achieve the magnitude of emissions reduction required from mobile source emissions in order to achieve RFP milestones and/or attain the NAAQS.

Once policy-makers for a given area have selected specific TCMs for modeling analysis in order to demonstrate the emissions reductions required for a SIP revision, it is important to recognize that some transportation models traditionally used to assess the need for expanded highway capacity are not designed for or capable of quantitatively assessing the VMT-reduction effects of some of the strategies listed here.

Traditional models do not have algorithms capable of assessing the effects of price on driver behavior and are especially ill-suited to test the different impacts on travel demand and mode split likely to be achieved by implementing alternative pricing strategies. Models can assess the differences in travel demand likely to result from two alternative regional-scale land use scenarios, but are less suited to evaluating the benefits of regional policies that affect land use iteratively, such as policies that increase bike/pedestrian access to transit or that promote neighborhood retail outlets as a strategy to reduce travel demand.

As a result, planners may find that a given mix of TCMs may appear potentially attractive as a regional package of options, but when tested using traditional transportation models, show little or no benefits compared to those claimed for the measures in *Tables 1 and 2*. This result may be an artifact of a model that was never designed to assess these kinds of measures on travel demand or mode split.

There is little value in engaging in a SIP-planning process with an outdated transportation model as the only tool for evaluating the emissions reduction benefits of alternatives under consideration. It is, therefore, important to protect the political and financial investment in the planning process by upgrading the regional transportation model to give decision-makers a tool that will have the sensitivity needed to provide useful and reliable information. Without such a tool to test the choices resulting from the planning process, the resulting SIP could prove far more costly than it need be or far less effective than it could be.

Federal Rulemaking and/or Guidance Documents

In March 1992, EPA published *Transportation Control Measure Information Documents,* which address the TCMs identified in Section 108 of the CAAA.

References

1. U.S. Environmental Protection Agency, Office of Mobile Sources. March 1992. *Transportation Control Measure Information Documents.*

2. U.S. Environmental Protection Agency. March 1992. *General Preamble Title I Clean Air Act Amendments 1990.*

3. U.S. Environmental Protection Agency, Office of Mobile Sources. Spring 1992. *Transportation Control Measures: State Implementation Plan Guidance.* Revised Guidance.

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6. Environmental Defense Fund, Michael Replogle. July 1993. *Motor Vehicle Use and the Clean Air Act: Boosting Efficiency by Reducing Travel.* Draft.

7. Environmental Defense Fund, Michael Replogle. April 1993. *Transportation Conformity and Demand Management: Vital Strategies for Clean Air Attainment.*

Table 1

Estimates of VMT-Reduction Potential of TCMs in U.S. Urbanized Areas

Potential Aggregate VMT Reduction Growth Trends	Category in 1992 EPA TCM Info Documents[1]	Apogee/NARC Estimated VMT Reduction[2]		EDF Estimated VMT Reduction For All Daily Travel[3]		
		Max in Lit.	Potential	1996	2000	2010
A. Pricing Measures	—	**14.5**	**12.6**	**4.5**	**9.0**	**18.7**
Cash Out Employer-Paid Parking & Boost Parking Fees	#2,8	4.0	3.0	1.6	2.3	4.2
Parking Pricing for Non-Work-Related Destinations	#8	4.2	4.2	0.7	2.1	3.8
Pay-As-You Drive Auto Insurance ($.50/gal)	—	—	—	1.0	1.9	2.5
Smog/VMT Tax	—	0.6	0.4	0.1	0.2	0.5
IVHS Automated Toll Express Lanes/Congestion Pricing	—	5.7	5.0	0.0	0.9	4.7
Central Area Pricing	—	—	—	0.0	0.1	0.3
Transit Fare Integration, Marketing, Pass Subsidy	#5	—	—	1.0	1.5	2.9
B. New Options for Short Trips	—	**0.0**	**0.0**	**0.9**	**3.2**	**8.0**
Traffic Calming, Bicycle/Pedestrian Improvements	#10	0.0	0.0	0.9	2.7	5.4
Develop Traffic Cells in Selected Primary Centers	#12	—	—	0.0	0.5	2.6
C. Smart Systems & New Technologies	—	**3.4**	**1.1**	**0.5**	**2.7**	**6.6**
IVHS Advanced Transit Information Systems	#5	—	—	0.4	1.1	2.9
Smart Communities: Teleshopping & Telelogistics	—	—	—	0.1	1.5	3.6
Telecommuting	#3	3.4	1.1	0.0	0.1	0.1
D. Growth Management and Land Use Policies	—	**5.4**	**5.4**	**0.4**	**2.7**	**9.5**
Encourage Accessory Apartments, Neighborhood Retail	#14	—	—	0.3	2.0	5.0
Growth Management Favoring Infill/Clustering/Centers	#14	5.4	5.4	0.1	0.7	4.5
E. Improved Public Transportation	—	**2.6**	**1.0**	**1.5**	**3.4**	**7.3**
Expanded Paratransit Services	#5	—	—	0.6	1.2	2.5
New Rail Starts & Major Transit Investment/Improvements	#5	2.6	1.0	0.4	1.1	2.6
Enhanced Bicycle/Pedestrian Access to Transit	#5,10	—	—	0.5	1.0	2.1
F. Marketing and Incentives	—	**5.9**	**2.2**	**1.3**	**2.7**	**3.6**
Employer Trip Reduction Programs	#1,2	3.3	1.0	0.5	1.0	1.0
Compressed Work Week	#3	0.6	0.8	0.1	0.3	0.2
Public Education Campaigns for New Transportation Ethics	—	—	—	0.5	1.0	2.0
Area Wide Ridesharing Programs	#4	2.0	0.4	0.1	0.4	0.4
G. Automobile Infrastructure	—	**1.8**	**1.8**	**-0.1**	**-0.8**	**-2.0**
HOV Lanes	#6	1.4	1.4	0.1	0.4	0.7
Park-and-Ride Lots	#9	0.5	0.5	0.1	0.3	0.5
Traffic Signal Timing/Intersection Traffic Flow Enhancement	#7	-0.0	-0.0	-0.3	-0.9	-2.0
Traffic Incident Management	#7	-0.1	-0.1	-0.1	-0.6	-1.2
H. Miscellaneous: Temporary & Non-VMT Related	—	—	—	—	—	—
Special Events Management	#11	—	—	—	—	—
Accelerated Retirement of Vehicles	#13	—	—	—	—	—
Controls on Extended Vehicle Idling	#15	—	—	—	—	—
Controls on Low-Temperature Cold Starts	#16	—	—	—	—	—
Total Reduction from Growth Trend	—	**33.6**	**24.0**	**8.9**	**22.9**	**51.7**
Growth Trend: Ratio to 1990	—	—	—	1.1	41.23	1.42
With Comp. Demand Management: Ratio to 1990	—	—	—	1.05	1.00	0.90

[1] *Cambridge Systematics, Inc. for the U.S. Environmental Protection Agency, Office of Mobile Sources. Transportation Control Measure Information Documents. March 1992.*

[2] *Apogee Research, Inc. for the National Association of Regional Councils. Costs and Effectiveness of Transportation Control Measures (TCMs): A Review and Analysis of the Literature (draft study). April 1993. Preliminary data subject to changes.*

[3] *Environmental Defense Fund estimates based on literature review and analysis by Michael Replogle, EDF. July 1993. (For additional information on assumptions and sources, see Transportation Conformity and Demand Management: Vital Strategies for Clean Air Attainment by Michael Replogle, EDF April 30, 1993.)*

Table 2

Average Estimated Potential of Comprehensive Transportation Demand Management in U.S. Urbanized Areas, By Trip Purpose[1]

Potential Aggregate VMT Reduction From Growth Trends by Trip Purpose	Estimated VMT Reduction (percent) Daily Travel			Estimated VMT Reduction (percent) Work Travel			Estimated VMT Reduction (percent) Non-Work Travel		
	1996	2000	2010	1996	2000	2010	1996	2000	2010
A. Pricing Measures	**4.5**	**9.0**	**18.7**	**7.3**	**15.5**	**31.5**	**3.4**	**6.7**	**15.0**
Cash Out Employer-Paid Parking & Boost Parking Fees	1.6	2.3	4.2	5.0	7.5	11.0	0.3	0.5	2.0
Parking Pricing for Non-Work-Related Destinations	0.7	2.1	3.8	0.0	0.8	1.5	1.0	2.5	4.5
Pay-As-You Drive Auto Insurance ($.50/gal)	1.0	1.9	2.5	1.0	3.0	4.0	1.0	1.5	2.0
Smog/VMT Tax	0.1	0.2	0.5	0.1	0.2	0.5	0.1	0.2	0.5
IVHS Automated Toll Express Lanes/Congestion Pricing	0.0	0.9	4.7	0.1	2.0	10.0	0.0	0.5	3.0
Central Area Pricing	0.0	0.1	0.3	0.1	0.5	2.0	0.0	0.0	0.0
Transit Fare Integration, Marketing, Pass Subsidy	1.0	1.5	2.9	1.0	1.5	2.5	1.0	1.5	3.0
B. New Options for Short Trips	**0.9**	**3.2**	**8.0**	**0.5**	**2.5**	**6.5**	**1.0**	**3.5**	**8.5**
Traffic Calming, Bicycle/Pedestrian Improvements	0.9	2.7	5.4	0.5	2.0	3.5	1.0	3.0	6.0
Develop Traffic Cells in Selected Primary Centers	0.0	0.5	2.6	0.0	0.5	3.0	0.0	0.5	2.5
C. Smart Systems & New Technologies	**0.5**	**2.7**	**6.6**	**1.2**	**3.0**	**6.0**	**0.3**	**2.6**	**6.8**
IVHS Advanced Transit Information Systems	0.4	1.1	2.9	0.5	1.5	2.5	0.3	1.0	3.0
Smart Communities: Teleshopping & Telelogistics	0.1	1.5	3.6	0.0	0.0	0.0	0.2	2.0	4.8
Telecommuting	0.0	0.1	0.1	0.7	1.5	3.5	-0.2	-0.4	-1.0
D. Growth Management and Land Use Policies	**0.4**	**2.7**	**9.5**	**0.4**	**2.5**	**8.0**	**0.4**	**2.8**	**10.0**
Encourage Accessory Apartments, Neighborhood Retail	0.3	2.0	5.0	0.3	2.0	5.0	0	3 2.0	5.0
Growth Management Favoring Infill/Clustering/Centers	0.1	0.7	4.5	0.1	0.5	3.0	0.1	0.8	5.0
E. Improved Public Transportation	**1.5**	**3.4**	**7.3**	**1.1**	**3.0**	**6.5**	**1.6**	**3.5**	**7.5**
Expanded Paratransit Services	0.6	1.2	2.5	0.2	0.5	1.0	0.7	1.5	3.0
New Rail Starts & Major Transit Investment/Improvements	0.4	1.1	2.6	0.4	1.5	3.0	0.4	1.0	2.5
Enhanced Bicycle/Pedestrian Access to Transit	0.5	1.0	2.1	0.5	1.0	2.5	0.5	1.0	2.0
F. Marketing and Incentives	**1.3**	**2.7**	**3.6**	**3.0**	**6.0**	**7.0**	**0.5**	**1.0**	**2.0**
Employer Trip Reduction Programs	0.5	1.0	1.0	2.0	4.0	4.0	0.0	0.0	0.0
Compressed Work Week	0.1	0.3	0.2	0.5	1.0	1.0	0.0	0.0	0.0
Public Education Campaigns for New Transportation Ethics	0.5	1.0	2.0	0.5	1.0	2.0	0.5	1.0	2.0
Area Wide Ridesharing Programs	0.1	0.4	0.4	0.5	1.5	1.5	0.0	0.0	0.0
G. Automobile Infrastructure	**-0.1**	**-0.8**	**-2.0**	**0.0**	**0.5**	**1.0**	**-0.2**	**-1.3**	**-3.0**
HOV Lanes	0.1	0.4	0.7	0.5	1.5	3.0	0.0	0.0	0.0
Park-and-Ride Lots	0.1	0.3	0.5	0.5	1.0	2.0	0.0	0.0	0.0
Traffic Signal Timing/Intersection Traffic Flow Enhance.	-0.3	-0.9	-2.0	-0.5	-1.0	-2.0	-0.2	-0.8	-2.0
Traffic Incident Management	-0.1	-0.6	-1.2	-0.5	-1.0	-2.0	0.0	-0.5	-1.0
Total Reduction from Growth Trend	**8.9**	**22.9**	**51.7**	**13.5**	**32.5**	**65.5**	**7.2**	**20.1**	**49.8**
Growth Trend: Ratio to 1990	1.14	1.23	1.42	1.14	1.23	1.42	1.14	1.23	1.42
With Comp. Demand Management: Ratio to 1990	1.05	1.00	0.90	1.00	0.91	0.77	1.07	1.03	0.92

Assumed Composition of Travel by Purpose	1990	1996	2000	2010
Percent of VMT for Work Travel	28	27	26	24
Percent of VMT for Non-Work Travel	72	73	74	76

[1]*Estimates based on literature review and analysis by Michael Replogle, Environmental Defense Fund, July 1993. For additional information on assumptions and sources, see Transportation Conformity and Demand Management: Vital Strategies For Clean Air Attainment by Michael Replogle, EDF; April 30, 1993.*

Employee Commute Options

Description of Control Measure

Section 182(d)(1)(B) of the Clean Air Act Amendments of 1990 requires employers with more than 100 employees located in Severe or Extreme ozone nonattainment areas to increase the average passenger occupancy per employee vehicle to a level 25 percent above the average vehicle occupancy for the nonattainment area as a whole. In order to comply with the Employee Commute Options (ECO) program requirement, each state with a Severe or Extreme ozone nonattainment area must establish a process of plan submission, approval, periodic reporting on target achievements and plan revision to achieve the applicable target. Employers are required to develop compliance plans with strategies to reduce work-related vehicle trips and vehicle miles traveled (VMT) during peak traffic periods.

Pursuant to the provisions of the CAAA, the following areas are required to implement an ECO program: Los Angeles, CA; San Diego, CA; Southeast Desert Modified Air Quality Management Area (San Bernadino, CA); Ventura County, CA; New York/New Jersey/Connecticut Metropolitan Area; Philadelphia, PA/Wilmington, DE/Trenton, NJ; Chicago, IL/IN; Baltimore, MD; Houston/Galveston/Brazoria, TX; and Milwaukee, WI.

EPA estimates that this program will affect approximately 28,000 employers with roughly 11-12 million employees.

Available Control Strategies

EPA has issued ECO guidance that identifies the following measures as examples of steps that employers may take to meet the program requirements: 1) provide direct financial incentives to promote commute modes other than driving alone; 2) sponsor or subsidize car/van pools; 3) subsidize use of public transit; 4) institute compressed work weeks; 5) offer telecommuting and work-at-home options; 6) provide comprehensive rideshare matching services; 7) subsidize mid-day shuttles to local shopping areas; 8) provide company-owned fleet vehicles for ridesharing; 9) charge those who drive alone for parking; 10) offer preferential or subsidized parking for car/van pools; 11) provide a guaranteed ride home program; and 12) improve facilities to promote bicycle use.

Potential National Emissions Reduction

EPA estimates that the ECO program can result in a one- to two-percent reduction in VMT. Actual benefits will depend upon the percent of total VMT derived from work trips; the percent of employees working for large companies subject to the program; the percent of work trips that occur during peak hours; the degree of employer compliance in preparing and implementing an incentive plan; and the effectiveness of the incentives offered by employers. These variables will be specific to each nonattainment area.

Federal Rulemaking and/or Guidance Documents

EPA issued final guidance on the ECO program in March 1993.

State and Local Control Efforts

Fourteen State Implementation Plans (SIPs) from 11 states were due for ECO to EPA on November 15, 1992. Of the 14 affected areas:

- Thirteen have final state/district ECO rules (a final rule for the fourteenth area—Maryland—is expected in July 1994).
- Twelve have submitted ECO SIPs to EPA (the remaining two—Maryland and Illinois—are expected to be submitted in July 1994).
- Two areas—Los Angeles, CA and Ventura County, CA—are currently implementing programs, as discussed below.
- EPA has, to date, proposed to approve two ECO SIPs—those for Los Angeles, CA and the Houston/Galveston/Brazona, TX area.

Many affected areas will begin implementing ECO programs in 1994.

In Los Angeles, the SCAQMD's Rule 1501 "Work Trip Reduction Plan," was originally adopted December 11, 1987 and has been amended several times, most recently on June 1, 1993. The SCAQMD recently established a task force to consider additional changes to the program to make it more acceptable to the area's approximately 5350 worksites operated by affected private companies and public agencies.

Ventura County APCD Rule 210, "Employee Commute Option," was originally adopted June 13, 1989 and was revised April 6, 1993. The rule became effective June 30, 1993 and applies to all public and private employers with fifty or more employees at any worksite. The average vehicle ridership targets for 1993 and beyond are shown in *Table 1*.

STAPPA/ALAPCO
Recommendation

▶ For areas not already required by the Clean Air Act to adopt an ECO program, implementation of such a program may offer additional reductions and could be an important strategy for stabilizing mobile source emissions.

References

1. U.S. Environmental Protection Agency, Office of Mobile Sources. March 1993. *Final Guidance on Employee Commute Options Program.*

Table 1

Average Vehicle Ridership Targets: Ventura County APCD Rule 210—Employee Commute Option Program

Year of Plan Submittal Deadline	Employer Size: Less than 100 Employees	Employer Size: 100 or more Employees
1993	1.35	1.35
1994 and 1995	1.35	1.35 plus measures to meet 1.50 by 1/1/97.
1996	1.35	1.50
1997 and after	1.50	1.50

Source: Ventura County Air Pollution Control District.

Accelerated Vehicle Retirement

Description of Control Measure

Old automobiles with no or few emissions controls are typically a source of high emissions. While normal attrition of the fleet alleviates a portion of these emissions, some high-emitting vehicles remain in operation and contribute to emissions problems for long periods of time. It is these vehicles that accelerated vehicle retirement programs—also known as scrappage programs—seek to remove from the fleet by providing an incentive for owners to retire these vehicles sooner than they would have in the absence of a program.

A state or local government can design a scrappage program as a SIP measure or, in conjunction with a private company, as a program to generate emissions credits to satisfy existing or new source-specific requirements.

In order to ensure that scrappage programs yield the expected levels of emissions reductions, minimum safeguards should be provided in order to receive credit. If the following program design elements are not present, EPA will consider the program elements on a case-by-case basis due to greater uncertainty of emissions reduction claims.

Vehicle Must Meet Twelve-Month Registration Requirement. To ensure that vehicles are not imported into the area for the sole purpose of being sold in the program, eligible vehicles must have been registered by the owner at an address within the nonattainment area continuously for at least the previous twelve months prior to the date the vehicle is purchased by the program.

Vehicle Must Be Operable and Driven to Site. Scrappage programs should seek to remove those high-emitting vehicles that would have been operated in future years and not to attract vehicles that are inoperable or have little remaining useful life. Eligible vehicles are required to be operable and driven to the intake site to increase the probability that the scrappage program will attract in-use vehicles. In addition, they must undergo a physical inspection designed to assure that major body components have not been removed and that the vehicle could be readily used for normal transportation purposes.

Owner Must be Present and Possess Valid Title. The owner of the vehicle or his or her legal representative or, in the case of corporate-owned vehicles, a certified agent, must be present to ensure proper passage of title and to verify the owner's intention to retire the vehicle. Since these vehicles will be either destroyed or dismantled for partial recycling, they cannot be returned to the owner if a mistake is made. The identification of the person delivering the vehicle, the Vehicle Identification Number and the validity of the vehicle title must be verified.

Owner Must Have a Valid I/M Certificate. As a further assurance that the vehicle being retired is an in-use vehicle, where motor vehicle Inspection and Maintenance (I/M) programs are in effect, scrappage programs must require vehicle owners to present the I/M certificate (or waiver certificate, if the car received a waiver) obtained from the most recent testing period.

Vehicles Must be Disposed of in an Environmentally Safe Manner. A scrappage program will generate solid, liquid and gaseous waste that must be disposed of or recycled in an environmentally sound manner. EPA requires that all retired vehicles be scrapped by facilities that are licensed and approved to dispose of all the types of waste created by the scrappage of vehicles or recycling of vehicle parts, where licensing requirements apply. In areas where such licensing requirements are not in place, programs must adhere to all applicable federal, state and local recordkeeping procedures and laws for disposal of vehicles. Where legal requirements are not in effect, all prudent environmental safeguards should be strictly followed to ensure that scrappage of vehicles does not result in environmental degradation.

Sponsors Must Provide Emissions Estimates Based Upon Certain Criteria. The most recent version of EPA's MOBILE model must be used for program evaluations begun three months or more after the release of an updated model. As an alternative to the MOBILE model's average emissions approach, program sponsors may choose to use actual tested emissions levels as the basis for emissions estimates. For the purpose of quantifying those emissions levels, a transient mass exhaust emissions test and, if desired, an evaporative emissions test procedure should be used. If this approach is used, other program design elements will be required to guard against the possibility of tampering to increase emissions and the resulting credits.

Sponsors of Programs Over 2500 Vehicles are Subject to Minimum Data Gathering Requirements. Sponsors retiring more than 2500 vehicles within any twelve-month period are subject to a minimum data-gathering requirement. Sponsors must collect emissions data, using EPA's IM240 mass emission test and evaporative purge and pressure tests, from a random sample of a statistically significant number of participating vehicles. Sponsors must also collect information on annual vehicle miles traveled (VMT), expected remaining useful life and model year of replacement vehicle. The information will be provided to EPA for evaluation of program emissions estimates and for the purpose of improving future guidance on emissions reduction estimates for scrappage programs.

STAPPA/ALAPCO
Recommendation

▶ Areas should consider implementation of a vehicle scrappage program in conjunction with an I/M program.

Available Control Strategies

While the potential for variations exists, scrappage programs will basically work in the following way. A state or local government or company would advertise for the purchase of certain vehicles. Owners would then voluntarily sell their vehicles to the sponsor of the program and the vehicles would be removed from the fleet. The sponsor would receive an emissions credit for each car removed from operation equivalent to the difference between the emissions from the retired vehicle and the emissions from the replacement vehicle. EPA encourages the consideration of programs that include trucks.

Basic scrappage programs can be varied by changing the focus of vehicle selection from general model-year eligibility to emissions-level eligibility. EPA encourages scrappage programs to focus on high emitters and recognizes that there are many possible program variations that could assist in that regard. Some may require alternative assumptions or other modifications to the basic methodology for the calculation of emissions reductions.

EDF/GM Test and Pool Approach. A scrappage program proposal designed by the Environmental Defense Fund (EDF) and General Motors Corporation (GM) addresses some of the inherent areas of uncertainty and is conducive to establishment of an ongoing program. The EDF/GM design targets high-emitting vehicles regardless of age, awards emissions reduction credits on the basis of emissions testing for each scrapped vehicle and creates an emissions reduction "pool" for the purpose of nullifying the incentive to tamper with individual vehicles.

Under the program, vehicles are purchased for a negotiated amount reflecting the local market price for emissions reduction credits in the area and generic information about the emissions and expected remaining life of the specific vehicle model and vintage. Presumably, in an active, ongoing program, private parties would accumulate and circulate such information, just as the retail market for used cars has created a "Blue Book," recording generic information about the transportation value of vehicles. Following purchase, the buyer would present the vehicle to an independent testing center where the emissions would be measured. The emissions results, factored by projected annual VMT and remaining life, would be included in pools of emissions results from all cars purchased by scrappage sponsors in the area. Emissions values would be reduced to reflect the emissions from replacement vehicles. Such pools would be created for each year of expected remaining life.

As an added assurance that the program provides net emissions reductions, each year's emissions pool would be discounted by 10 percent. The remainder of the annualized emissions pool would be distributed in the form of transferable mobile emission reduction credits (MERCs) to each scrappage sponsor on a pro-rata basis reflecting the sponsor's share of all scrapped vehicles whose emissions were included in the pool.

To bolster the pooling approach for minimizing the incentive for sponsors to tamper with vehicles to increase their emissions, local regulatory authorities would adopt an oversight procedure. By selling a "control" vehicle with known emissions to a scrappage sponsor and obtaining the emissions test results from the independent test facility, tampering could be detected. Stiff penalties for tampering, including disqualifying the sponsor from future scrappage programs and disallowing MERCs already generated by the sponsor, would nullify the incentive to tamper, while also ensuring that any tampering already committed would not have an adverse effect on air quality.

Scrappage and Remote Sensing. Programs that use a remote sensing device (RSD) to target vehicles for participation in a scrappage program may reduce some of the uncertainty found in programs with eligibility based only on age and improved cost effectiveness. Specifically, use of an RSD may increase program cost effectiveness by identifying older cars that are higher emitters than the average car of their age and reduce credit overestimation by identifying vehicles that are actually in active service and not just being stored or infrequently used. Scrapping only vehicles identified by on-road remote sensing should, therefore, produce more emissions reductions per scrapped vehicle. EPA encourages consideration of this approach. However, if the emissions estimates used for calculating the MERCs are to be increased over those predicted by the MOBILE model, transient mass emissions testing is required to determine how much larger the increases should be. Special program design elements should also be included to guard against intentional tampering for the purpose of increasing emissions and the resulting credits. An EDF/GM-type measuring approach is one solution.

Scrappage and I/M Programs. Adding a vehicle scrappage option to a motor vehicle Inspection and Maintenance (I/M) program is another way to improve program benefits and/or reduce costs. I/M programs require vehicles to pass an emissions test in order to be registered or licensed for operation. If a vehicle does not pass the test, owners are required to make repairs up to a certain dollar amount. If, after making the repairs, the vehicle still cannot pass the test, the owner may receive a waiver allowing the vehicle to be licensed for use until the next scheduled test.

By incorporating a scrappage component into the I/M program, vehicles that fail an I/M test, and which have not yet been successfully repaired or are known to need repairs costing more than a predetermined amount, would become eligible for scrappage. Depending upon the estimated cost of repair, emissions reduction credits would be based upon either the vehicle's emissions levels from an IM240 test or emissions estimates from the MOBILE model.

For example, vehicles requiring less than $300 in repairs would be assigned the MOBILE estimate of emissions levels for the appropriate model year. Vehicles requiring $300-$450 in repairs would be assigned an emissions level that is less than the initial IM240 test results, to reflect the repairs and the post-repair emissions levels likely to be reached in absence of the scrappage option. This post-repair emissions level is derived from the TECH5 relationship between initial test emissions levels and post-repair test emissions levels. Vehicles requiring in excess of $450 in repairs would be assigned emissions levels based upon their initial I/M transient test. It should be noted that serviceability and repair costs are difficult to predict without professional diagnosis. Furthermore, a conflict of interest could occur if the diagnosis were performed by someone whose judgment may be influenced by the sponsor of the scrappage program. Therefore, it is reasonable to require proof of an independent professional diagnosis that supports the cost estimate.

Scrappage program designs that incorporate an I/M element in this way will not only have greater assurance that they are retiring high-emitting vehicles, but could possibly result in lower purchase costs for the sponsors, as well as an increased incentive to scrap for the vehicle owner, who will likely be faced with immediate repair costs if the vehicle is not scrapped. EPA encourages this approach as a way to increase the assurance of environmental benefits and as an environmentally sound option to issuing a waiver to a high-emitting vehicle. As with the EDF/GM approach and the remote sensing approach described above, special program features to guard against cheating or fraud would be required.

POTENTIAL NATIONAL EMISSIONS REDUCTION

The emissions most reduced by vehicle scrappage programs are VOCs and CO; NO_x reductions due to vehicle scrappage are relatively small.

EPA has developed an example to illustrate the methodology for determining emissions reductions. The hypothetical example is based upon data representing national fleet averages and may not be representative of any particular urban area. *Table 1* provides an estimate of the emissions reductions that could be realized from a program operating in 1993, in which 10,000 pre-1980 model vehicles are retired.

All of the emissions estimates were made using MOBILE4.1. Baseline and post-program scenarios use national average default values to describe the vehicle fleet, standard speeds and typical summer temperatures. The scenarios assume a low-altitude area with an American Society for Testing and Materials (ASTM) Class C fuel. The area is also assumed to have an existing basic I/M program with an idle test covering all model years of vehicles.

A step-by-step description of the base methodology and how it was applied to the example follows and is shown in *Table 2*. VOC emissions reductions are used in this example, but NO_x emissions reductions could also be calculated using this methodology.

1. **Estimate the model years and number of vehicles to be retired**. For this example, the model year distribution of the participating vehicles is assumed to be identical to that of the eligible fleet and is based upon the national fleet model year distribution from MOBILE4.1. It is assumed that 10,000 pre-1980 model year vehicles are scrapped on January 1, 1993.

2. **Estimate changes in fleet size**. For this example, it is assumed that the total number of vehicles in the fleet remains the same as before the program was implemented.

3. **Estimate changes in VMT**. EPA's approach keeps total VMT the same before and after the program. The values are determined by the annual mileage accumulation in the MOBILE model and are supported by data reported by Oak Ridge National Laboratory in the Transportation Energy Data Book: Edition 11, and also by data collected by UNOCAL during the demonstration program in Los Angeles during the summer of 1990. The average VMT per year per retired vehicle is 5182 miles in the first year, 4920 miles in the second year and 4680 miles in the third year.

4. **Estimate the expected number of years of use remaining for the retired vehicles**. The expected number of years of use remaining in the retired vehicles is three years.

5. **Estimate the average emissions per year from the retired vehicles.** The average emissions from the retired vehicle were estimated by MOBILE4.1, using national average characteristics for climate, geography, local control program and vehicle fleet (e.g., altitude, fuel, I/M program, fleet, travel fraction). The MOBILE model was then run for three successive years—1993, 1994 and 1995. The average emissions were determined by running the model with zero registrations and zero mileage accumulation for 1980 and newer model years. The average grams per mile (gpm) are indicated at the bottom of the column labeled FER in the MOBILE4.1 output table. The emissions levels for the retired vehicles in each of the three years were as follows: 8.87 gpm in 1993, 9.06 gpm in 1994 and 9.26 gpm in 1995.

6. **Estimate the average emissions per year from the replacement vehicles**. The estimates of the average emissions from the entire post-program fleet were based on the same national average characteristics mentioned above. To estimate the average emissions of the replacement vehicles, the MOBILE model should be run for all model years for 1993, 1994 and 1995. The average grams per mile will be indicated in the column labeled FER in the MOBILE4.1 output table. The emissions levels for the replacement vehicles in each of the three years were as follows: 2.20 gpm in 1993, 2.09 gpm in 1994 and 2.00 gpm in 1995.

7. **Calculate the average yearly emissions benefit for each retired vehicle**. Subtract the result of step 6 from the result of step 5 and multiply by the average VMT per scrapped vehicle, as determined in step 3, for each calendar year. The results are 34,564 grams/vehicle in 1993, 34,292 grams/vehicle in 1994 and 33,977 grams/vehicle in 1995.

8. **Calculate the total emissions reduction in tons per year removed by the program**. Multiply the average emissions benefit for each retired vehicle by the effective number of vehicles retired and convert to tons for each calendar year. To determine the effective number of vehicles for each year, reduce the number of scrapped vehicles by the "normal" retirement rate. For this example, the national rate of decline of 20 percent per year will be assumed, starting immediately after the scrappage event. Averaged over each of the three years, the effective number of vehicles for each year is 9000, 7200 and 5760, respectively.

Federal Rulemaking and/or Guidance Documents

In February 1993, EPA published guidance on the generation of mobile source emissions reduction credits and on the implementation of an accelerated retirement program for motor vehicles.

State and Local Control Efforts

The SCAQMD has a vehicle scrappage regulation in effect (Rule 1610—Old Vehicle Scrappage, as amended January 14, 1994). In addition, the California Air Resources Board published a document entitled *Mobile Source Emission Reduction Credits* (February 1993), that addresses, among other issues, the generation of emissions reduction credits through the accelerated retirement of older vehicles. Additional CARB guidance was published in February 1994.

At least four additional states — Colorado (Denver), Delaware (U.S. Generating Co.), Pennsylvania (Sun Oil) and Illinois (Illinois EPA) — are initiating demonstration programs, while others — including New Jersey, Texas, Louisiana, Virginia, Oklahoma and Michigan — are considering implementing such programs.

References

1. U.S. Environmental Protection Agency, Office of Mobile Sources. February 23, 1993. *Guidance on the Generation of Mobile Source Emission Reduction Credits*. (58 *Federal Register* 11134).

2. U.S. Environmental Protection Agency, Office of Mobile Sources. February 1993. *Guidance for the Implementation of Accelerated Retirement of Vehicles Programs*.

Table 1

Estimated Emissions Reductions from a Program to Retire 10,000 Vehicles in 1993

Year	NO_x Emission Reduction (tons)
1993	115
1994	91
1995	72
Total	278
Avg/Yr	93

Source: EPA.

Table 2

Example Hydrocarbon Emission Reduction (assuming 10,000 pre-1980 model year vehicles scrapped on 1/1/93)

		1993	1994	1995
HC/Retired Vehicle (gpm)		8.87	9.06	9.26
HC/Replacement Vehicle (gpm)	–	2.20	2.09	2.00
HC Reduction/Vehicle (gpm)	=	6.67	6.97	7.26
VMT/Year/Retired Vehicle	x	5182	4920	4680
Grams/Vehicles/Year	=	34564	34292	33977
Effective Number of Vehicles[1]	x	9000	7200	5760
Conversion (Grams to Tons)	x	.000001102	#	#
Tons Per Year	=	343	272	216

[1]The analysis assumes that all of the retired vehicles would have been scrapped within three years. This method assumes a 20-percent scrappage rate per year for three years and provides for no reduction credit beyond the three-year remaining life assumption.

SECTION IV

Appendices

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APPENDIX A

Frequently Used Acronyms and Abbreviations

A/F – *Air-to-Fuel Ratio*
ACT – *Alternative Control Techniques*
AFUE – *Annual Fuel Utilization Efficiency*
AIRS – *Aerometric Information Retrieval System*
ALAPCO – *Association of Local Air Pollution Control Officials*
APCD – *Air Pollution Control District*

BAAQMD – *Bay Area Air Quality Management District*
BARCT – *Best Available Retrofit Control Technology*
BOF – *Basic Oxygen Furnace*
BOOS – *Burners Out-of-Service*

CAAA – *Clean Air Act Amendments of 1990*
CARB – *California Air Resources Board*
CEMS – *Continuous Emission Monitoring System*
CFFV – *Clean-Fuel Fleet Vehicle*
CI – *Compression Ignition*
CaO – *Calcium Oxide*
CO – *Carbon Monoxide*
CTG – *Control Techniques Guideline*

ECO – *Employee Commute Options*
EPA – *U.S. Environmental Protection Agency*
ESP – *Electrostatic Precipitators*

FGR – *Flue Gas Recirculation*
FBN – *Fuel Bound Nitrogen*
FF – *Fabric Filter*
FIP – *Federal Implementation Plan*
FCCU – *Fluid Catalytic Cracking Unit*

GVWR – *Gross Vehicle Weight Rating*

HC – *Hydrocarbons*
HRSG – *Heat Recovery Steam Generator*
HRT – *Horizontal Return Tubular (Boiler)*
HCl – *Hydrogen Chloride*

IC – *Internal Combustion (Engine)*

ILEV – *Inherently Low-Emission Vehicle*
I/M – *Inspection and Maintenance*
IPP – *Independent Power Producers*
ITR – *Ignition Timing Retard*

LAER – *Lowest Achievable Emission Rate*
LE – *Low Emission (Combustion)*
LEA – *Low Excess Air*
LEV – *Low-Emission Vehicle*
LNB – *Low NO_x Burner*
LNG – *Liquified Natural Gas*

MACT – *Maximum Achievable Control Technology*
MSW – *Municipal Solid Waste*
MWC – *Municipal Waste Combustor*
MWI – *Medical Waste Incinerator*

NAAQS – *National Ambient Air Quality Standard*
NESCAUM – *Northeast States for Coordinated Air Use Management*
NGR – *Natural Gas Reburn*
NH_3 – *Ammonia*
NMHC – *Nonmethane Hydrocarbon*
NMOG – *Nonmethane Organic Gas*
NO – *Nitric Oxide*
N_2O – *Nitrous Oxide*
NO_x – *Nitrogen Oxide*
NSCR – *Nonselective Catalytic Reduction*
NSPS – *New Source Performance Standard*
NSR – *New Source Review*
NUG – *Non-Utility Generator*

OBD – *Onboard Diagnostics*
OFA – *Overfire Air*
OMB – *Office of Management and Budget*
OTC – *Ozone Transport Commission*

PC – *Pulverized Coal*
PSC – *Prestratified Charge*

RACT – *Reasonably Available Control Technology*
RB – *Radiant Burner*
RDF – *Refuse-Derived Fuel*
RFG – *Reformulated Gasoline*
ROG – *Reactive Organic Gas*
RSD – *Remote Sensing Device*
RVP – *Reid Vapor Pressure*

SCAQMD – *South Coast Air Quality Management District*
SCR – *Selective Catalytic Reduction*
SI – *Spark Ignition*
SIC – *Standard Industrial Classification*
SIP – *State Implementation Plan*
SNCR – *Selective Noncatalytic Reduction*
SO_2 – *Sulfur Dioxide*
SO_3 – *Sulfur Trioxide*
SOV – *Single-Occupancy Vehicle*
STAPPA – *State and Territorial Air Pollution Program Administrators*

TCM – *Transportation Control Measure*
THC – *Total Hydrocarbons*
TLEV – *Transitional Low-Emission Vehicle*
TTE – *Tire-to-Energy*

UBC – *Unburned Hydrocarbons*
ULEV – *Ultra Low-Emission Vehicle*

VMT – *Vehicle Miles Traveled*
VOC – *Volatile Organic Compound*

WI – *Water Injection*
WTE – *Waste-to-Energy*

ZEV – *Zero-Emission Vehicle*

APPENDIX B

Frequently Used Abbreviations for Units of Measure

ADTP – *Air-Dried Ton of Pulp*
atm – *atmosphere (760 mm Hg @ 0 °C)*

bbl – *barrel*
Btu – *British thermal unit*

g/bhp-hr – *grams per brake horsepower hour*
gpm – *grams per mile*

hr – *hour*
hp – *horsepower*

kg – *kilogram*
kW – *kilowatt*
kWh – *kilowatt hour*

lb – *pounds*
lb/MMBtu – *pounds per million Btu*

MM – *million*
MMBtu – *million British thermal units*
Mg – *megagram (10^6 gram)*
mmHg – *millimeters of mercury*
MW – *megawatt*
MWh – *megawatt hour*

Nm^3 – *normal cubic meters*

pph – *pounds per hour*
ppm – *parts per million*
ppmv – *parts per million volume*
ppmw – *parts per million weight*
psi – *per square inch*

rpm – *revolutions per minute*

tpd – *tons per day*
tpsd – *tons per summer day*
tpy – *tons per year*

APPENDIX C

National NO_X Emission Estimates by Source Category and State

Table 1

Total National NO_X Emissions by Source Category

Source Category	Total National NO_X Emissions (tons per year)
Utility Boilers	6,420,000
Industrial and Commercial Boilers	3,827,000
Process Heaters	169,000
Gas Turbines	165,000
Reciprocating Internal Combustion Engines	784,000
Kraft Pulp Mills	68,000
Cement Kilns	146,000
Iron and Steel Mills	135,000
Glass Furnaces	76,000
Nitric and Adipic Acid Plants	25,500
Municipal Waste Combustors	32,000
Ammonia Plants	25,700
Organic Chemical Plants	188,000
Petroleum Refineries	372,000
Residential Space and Water Heaters	334,500
Open Burning	7,110

Source: EPA, AIRS.

Table 2

1992 Point, Area and Total NO_x Emissions by State (thousand short tons)

State	Point Source Emissions	Area Source Emissions	Total Emissions	% Total Point NO_x Emissions	% Total Area NO_x Emissions	%Total NO_x Emissions
Alabama	284	247	531	2.73	1.94	2.29
Alaska	2	10	12	0.02	0.08	0.05
Arizona	137	249	386	1.32	1.95	1.67
Arkansas	106	151	257	1.02	1.19	1.11
California	299	1,150	1,449	2.88	9.01	6.26
Colorado	148	174	322	1.43	1.36	1.39
Connecticut	21	117	138	0.20	0.92	0.60
Delaware	31	31	62	0.30	0.25	0.27
District of Columbia	1	17	18	0.01	0.13	0.08
Florida	392	520	912	3.78	4.07	3.94
Georgia	313	378	691	3.02	2.96	2.98
Hawaii	12	21	33	0.11	0.17	0.14
Idaho	7	83	91	0.07	0.65	0.39
Illinois	442	448	889	4.25	3.51	3.84
Indiana	601	390	991	5.79	3.06	4.28
Iowa	150	150	300	1.45	1.17	1.30
Kansas	199	201	400	1.92	1.58	1.73
Kentucky	369	263	632	3.55	2.06	2.73
Louisiana	366	419	785	3.52	3.28	3.39
Maine	17	59	76	0.16	0.47	0.33
Maryland	117	203	320	1.13	1.59	1.38
Massachusetts	86	223	309	0.83	1.75	1.34
Michigan	349	436	785	3.26	3.41	3.39
Minnesota	179	201	380	1.72	1.57	1.64
Mississippi	105	187	292	1.01	1.47	1.26
Missouri	317	271	588	3.05	2.12	2.54
Montana	80	85	165	0.77	0.67	0.71
Nebraska	68	106	175	0.66	0.83	0.75
Nevada	69	68	137	0.67	0.53	0.59
New Hampshire	26	47	73	0.25	0.37	0.32
New Jersey	101	283	384	0.97	2.22	1.66
New Mexico	164	117	281	1.58	0.92	1.21
New York	226	535	761	2.18	4.19	3.29
North Carolina	237	346	583	2.28	2.71	2.52
North Dakota	133	53	185	1.28	0.41	0.80
Ohio	628	488	1,116	6.04	3.82	4.82
Oklahoma	205	225	430	1.97	1.77	1.86
Oregon	21	186	207	0.21	1.46	0.90
Pennsylvania	441	486	927	4.25	3.80	4.00
Rhode Island	1	32	33	0.01	0.25	0.14
South Carolina	119	174	292	1.14	1.36	1.26
South Dakota	22	43	65	0.22	0.34	0.28
Tennessee	296	252	547	2.85	1.97	2.36
Texas	1,374	1,498	2,872	13.23	11.73	12.41
Utah	130	98	228	1.25	0.77	0.99
Vermont	1	27	27	0.01	0.21	0.12
Virginia	137	315	451	1.32	2.46	1.95
Washington	108	265	373	1.04	2.08	1.61
West Virginia	342	103	446	3.30	0.81	1.92
Wisconsin	203	235	438	1.96	1.84	1.89
Wyoming	201	99	301	1.94	0.78	1.30
National	**10,383**	**12,765**	**23,146**	**100**	**100**	**100**

Source: EPA, National Air Pollutant Emission Trends, 1900-1992. EPA-454/R93-032, October 1993.

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